CHEMINFO

ALBERTA ENVIRONMENT EMISSION TRADING PROJECT

Major Feasibility Study

Preliminary Analysis and Discussion Document

Submitted to:
Alberta Environment

Project Team:

Cheminfo Services Inc. Markham, Ontario	HALOA Inc. Montreal, QC	Margaree Consultants Inc. Toronto, Ontario	Clearstone Engineering Inc. Calgary, Alberta

GLOSSARY

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APPENDIX A: MARKAL RESULTS

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APPENDIX B: Costs Of Technologies to NO_x & SO_x Emissions from Industrial & EPG Sources in Alberta

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APPENDIX C: Profile Criteria Air Contaminants, mercury and Greenhouse Gases Emissions in Alberta

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Executive Summary

Introduction

The purpose of this document was to assess the potential of emissions trading to help achieve broad air emission objectives for airborne pollutants and greenhouse gases efficiently and cost-effectively for the private and public sectors in Alberta.

Emissions trading, more precisely trading of emission rights (allowances or credits), is a form of environmental regulation that allows a specified emissions target for a group of sources to be achieved at lower cost. The participating sources and their collective emissions limit are determined by the regulatory authority. At the end of every compliance period, usually a year, each participant must submit allowances/credits equal to its actual emissions during the period to the regulatory authority. With compliance by all participants, total emissions cannot exceed the collective emissions limit.

Analyses

The document assessed the feasibility of emissions trading for sulphur oxides (SOx), nitrogen oxides (NOx), mercury (Hg), particulate matter (PM), volatile organic compounds (VOCs) and greenhouse gas emissions (GHGs) by large industrial sources in Alberta. A substance is considered suitable for emissions trading if:

- emissions by these sources are a significant share of total provincial emissions;
- their emissions are measurable and verifiable;
- the number of sources and distribution of emissions among these sources suggest a competitive market;
- participants have a variety of abatement options with different marginal costs;
- emissions trading does not raise environmental or health concerns; and
- participants have, or can acquire, the knowledge, competencies and culture needed for emissions trading.

Based on these criteria, SOx, NOx and GHG emissions by large industrial sources appear to be well suited to a province-wide emissions trading program. Alberta's climate change action plan assumes that emissions trading is a feasible approach to achieving its GHG emission reduction target for industrial sources. This assumption is confirmed. Particulate matter is not well suited to an emissions trading program for large industrial sources because those sources are responsible for only a small percentage of total emissions. VOCs are not a good candidate for emissions trading because of the low share of total emissions contributed by large industrial sources and the nature of the environmental impacts of VOC emissions in the province.

Mercury is not suitable for emissions trading in Alberta because three electricity generators dominate total emissions, so there would not be a competitive market for the allowances/

credits and because currently available monitoring systems can not measure mercury emissions continuously. If a mercury emission reduction target is established for coal-fired electricity generators, mercury emissions by these sources could be added onto a trading program for SOx, NOx and GHG emissions once suitable monitoring systems are available.

An emissions trading program requires a limit on the total emissions of the participants that is lower than their "business-as-usual" emissions. Since SOx, NOx and GHGs are recommended for inclusion in the trading program, limits lower than the "business-as-usual" emissions by large industrial sources are needed for all of those substances. Adoption of technologies to lower emissions of SOx, NOx, GHGs and mercury can increase or reduce emissions of the others. Since mercury emissions may be regulated, combinations of limits for all four substances must be analyzed to identify the actions that can meet the combined limits at least cost.

Modeling is used to identify the lowest cost actions to meet four sets of emissions targets. The first set consists of targets for GHGs and mercury. The GHG target is the provincial objective of reducing greenhouse gas emissions relative to Gross Domestic Product (GDP) by 50% from the 1990 level by 2020. This is expected to result in total emissions of 238 $MtCO_2e$ in 2010 and 218 $MtCO_2e$ in 2020. This target is divided between large industrial sources and other sources. The mercury target is to reduce emissions by coal-fired electricity generators by 50% from projected levels beginning in 2010. The other three sets of emissions targets use these same GHG and mercury targets, but add low, medium and high SOx (0%, 30% and 60% reduction from 2000 emissions in 2020) and NOx (+15%, 0% and -15% from 2000 emissions by 2020) reduction targets for large industrial sources beginning in 2010.

The targets for SOx, NOx and mercury are not regulatory proposals. They are simply arbitrary points in the range of possible emission reductions that are used to analyze how costs change as emission targets become more stringent. The cost rises exponentially as the SOx and NOx targets become more stringent. The cost of the most stringent set of targets analyzed is about 0.05% of the value of industrial sales over the period. The residential, commercial and transportation sectors also bear costs, in the form of higher bills for fossil fuels and electricity, due to the emissions targets.

The emissions targets analyzed do not affect oil and gas output; indeed exports rise slightly due to lower provincial demand. Non-energy industries typically experience a significantly lower growth rate, or a decline, in output between 2005 and 2010. The growth rates usually recover between 2010 and 2015, but are still lower than the "business-as-usual" projection. Meeting the emissions targets raises costs for these industries, so they become less competitive and their output declines relative to "business-as-usual".

The GHG target is the main determinant of the impact on output. Adding progressively more stringent SOx and NOx targets has virtually no impact on output. This is because the main options for reducing GHG emissions involve increased energy efficiency and fuel switching, which affect production processes. SOx and NOx emissions, in contrast, can be reduced by control technologies, which increase costs but do not change the production process.

The model calculates profits as revenues minus costs with no accounting adjustments such as depreciation. Profits are the present value of the profit changes over the period analyzed (2000 - 2020). Profits are often lower when the emissions trading program begins and rise after the emission reduction actions have been implemented. Profits are calculated for industry sectors because individual firms are not represented in the model. Profit impacts would vary across firms in the same industry.

The model estimates higher profits with emissions targets in the chemicals, electricity generation, oil refineries, and pulp and paper industries and lower profits in the cement, natural gas, and oil sands sectors relative to "business-as-usual". Conventional oil has lower profits in 2010 and 2015 and higher profits in 2020.

Higher profits are possible with an emissions target when the demand is relatively "inelastic"(oil refineries and electricity generation), which means that the price and revenue may increase even if production declines. The model assumes that these industries are competitive and sets the price equal to the marginal cost. Compliance with the emissions target increases the marginal cost and hence the price, the total revenue and profits. When the demand is highly elastic (chemicals and pulp and paper), the higher profits are the result of "no regret" emission reduction actions that yield net savings through lower energy costs that are not incorporated into the "business-as-usual" case.

Implementing the least-cost emission reduction actions reduces emissions from 2000 levels in all regions except Census Region 16 where the oil sands expansion occurs. Alberta Environment currently has no basis for considering that the projected SOx and NOx emissions in Region 16 would cause unacceptable health or environmental impacts. However, the Cumulative Effects Management Association (CEMA) is currently conducting studies and analyses that will guide future decisions regarding a SOx and/or NOx cap for the Ft. McMurray area.

The distribution of allowances or definition of baselines is one of the key issues in the design of an emissions trading program. It affects how the cost of achieving the emission reductions is distributed among participants. It can also affect the cost of achieving a specified emission target or change the total emissions.

A free allocation of allowances, or baseline, tied to output is equivalent to a production subsidy and so leads to higher output relative to an allocation that does not change with output. The emissions associated with the higher output increase the cost, relative to an allocation that does not vary with output, of meeting a given emissions target.

Four allowance distribution options were modeled. The options were deliberately defined to be significantly different and span the full range of possibilities. In practice intermediate cases, such as special treatment of new sources or a transition from free distribution to an auction, are possible. The analysis used the GHG, mercury, and medium SOx and NOx targets. Unlimited banking of GHG allowances/credits and limited banking of SOx and NOx allowances/credits were allowed as part of all four options. As expected, banking reduced the total cost of meeting the emissions targets.

The total cost is particularly sensitive to the method used to distribute GHG allowances. For the emissions target analyzed, the total cost is roughly four times higher when GHG allowances are distributed free, or the baseline is set, on the basis of output than if the GHG allocation, or baseline, is fixed (grandfathering). A free allocation based on output encourages higher output. To accommodate the emissions associated with that higher output within the fixed target requires larger and more costly reductions. Given a free output-based allocation for GHG allowances, the method of distributing SOx and NOx allowances has little impact on the total cost for the targets analyzed.

The rapid growth projected for the oil sands sector affects all participants. If the baseline or allocation is proportional to base year emissions (grandfathering), new oil sands projects must buy large quantities of allowances from the other industries, which results in a reduction of the projected profits of the oil sands sector. On the other hand, an output-based allocation leads to a shift in allowances from all other industries to the oil sands sector. The same happens in a baseline and credit design if the baselines are adjusted to meet the aggregate targets. The larger allocation (baseline) for the oil sands sector imposes higher costs on all other industries. In short, the choice of a distribution option depends to a significant extent on what is considered a fair distribution of the economic burden of the growing emissions of the oil sands sector.

The output of the energy producing industries -- conventional oil, natural gas, and oil sands -- is not affected by the distribution options analyzed. The output of the cement, chemicals, electricity generation, oil refining and pulp and paper industries is reduced by imposition of the emissions target. The output declines are smaller with an output-based allocation, or baselines that vary with output, than under a fixed allocation or baseline not tied to output. But even with an output-based allocation or baseline, the output growth in each of these industry sectors is lower than the "business-as-usual" projection.

For all of the allowance distribution options modeled, except an auction, profits are higher than under "business-as-usual" for cement, chemicals, conventional oil, oil refineries, and pulp and paper. Profits are lower than under "business-as-usual" for the natural gas (by negligible amounts) and oil sands sectors. The profits of electricity generators increase or decrease for different distribution options. The model is not able to analyze how the auction revenue is used. If some or all of the revenue is used to reduce taxes on industry, the adverse profit impacts would be smaller. The impact on profits by sector would depend on which taxes are reduced.

Profits are highest for all sectors, except oil sands and natural gas, with a fixed allocation of free allowances, or baseline, not tied to output. With an output-based allocation of free allowances, or baseline, tied to output, profits are lower than with a fixed allocation of free allowances, but still higher than under "business-as-usual" for all sectors except electricity generation, oil sands and natural gas (by a negligible amount).

Thus, for all sectors except oil sands and natural gas the choice is between:

- a fixed allocation of free allowances, or baseline, not tied to output whose consequences are higher profits but lower output than under "business-as-usual"; and
- an output-based allocation of free allowances, or baseline, tied to output whose consequences are higher output and lower profits than with a fixed allocation of free allowances, but still below the output and above the profits under "business-as-usual".

The output of the natural gas and oil sands sectors is constant for all of the options modeled, so only the profits change.

The profit impacts are most pronounced for the distribution of GHG allowances, but also apply, on a much smaller scale, to the distribution of SOx and NOx allowances.

The relatively large differences in profit impacts across sectors for the allocation options modeled suggest that no single allocation option will be acceptable for all industries. This implies that a combination of allocation options or a single option with adjustments for some sectors and/or entities probably will be needed. As noted above, the preferred distribution option depends to a significant extent on what is considered a fair distribution of the economic burden of the growing emissions of the oil sands sector.

The model results suggest that there will be enough buyers and sellers to create competitive markets for each of the substances. Participants are projected to purchase relatively large quantities of GHG allowances/credits from external sources. Thus, a competitive GHG allowance market in Alberta depends on Alberta participants having access to a large number of sellers outside the trading program. The SOx and NOx markets are assumed to be limited to the trading program participants for modeling purposes. The industries that are net buyers or net sellers of SOx and NOx allowances/credits are partly determined by the distribution of GHG allowances.

While the number of SOx and NOx buyers and sellers appears to be sufficient to create a competitive market in Alberta, provisions to ensure this is the case should be considered. Banking helps create a more competitive market. An auction also helps make the market more competitive. If all allowances are distributed free, the possibility of withholding some of the allowances for auction with the proceeds distributed to the participants in lieu of free allowances should be considered.

Recommendations

If an emissions trading program is implemented in Alberta, it should be implemented on a province-wide basis for the SOx, NOx and GHG emissions of large industrial sources. The trading program should include any facility whose annual SOx, NOx or GHG emissions exceed a specified emissions threshold or whose capacity exceeds the specified design capacity for that type of facility. A facility that exceeds any of the thresholds should be required to participate in the program for all of the substances.

The following approach is recommended for negotiating the distribution of allowances or establishment of baselines for participants in the emissions trading program.

- Emissions targets are defined for SOx, NOx and GHG emissions by large sources in all sectors excluding oil sands. Each of the industry sectors covered by those targets is allocated a share of the target based on its share of emissions in 2000 (or some other year or period to be agreed). These sector shares are adjusted every five years, or when the emissions caps change, based on the most recent year's actual emissions (or some other rule as agreed).

- The participants in each industry sector are offered a free allocation of allowances based on an agreed base period or based on current output. The choice between a fixed or output-based allocation would be binding on all participants in the sector. Industries choosing a fixed allocation would need to agree on a base period and reasonable allocations for new sources. Industry sectors choosing an output-based allocation, or baseline, must agree on a common measure of output and how it will be monitored. The allocations to individual participants would then be computed from and be constrained to the allocation to the sector.

- SOx, NOx and GHG allocations or baselines for oil sands projects are established separately. Those allocations or baselines should represent a reasonable contribution to reducing provincial emissions. The trading program targets for SOx, NOx and GHG would rise by the amount of the allocation to, or baseline for, each new project or major expansion when it commenced operation.

If baselines, rather than allowance allocations, are adopted, allowances equal to the baselines, rather than credits equal to reductions from the baseline, should be distributed to improve liquidity, especially in the SOx and NOx markets. Initially, allowances should be distributed free to participants, but with a transition to an auction once costs of emission reduction actions have been recovered and competitors elsewhere face similar emissions regulations.

Participants with compliance obligations should be individual facilities -- a facility located on a single contiguous site or operated independently -- such as an electricity generating unit, natural gas plant, oil refinery, cement plant, etc. Any person or entity should be allowed to buy or sell allowances and credits. The owner of an allowance or credit may request the regulatory authority to cancel the allowance or credit to benefit the environment.

An emissions trading program should seek to cover as many of the sources as possible within any facility that meets the threshold for participation. But it must be possible to measure or calculate the emissions of each source with reasonable accuracy at reasonable cost. Vehicle emissions are generally excluded, but the emissions of vehicles used in oil sands and mining operations should be included if they can be measured or calculated.

An emissions trading program should require participants to install the most accurate type of monitoring equipment, often continuous emission monitors; to regularly test the accuracy of the monitoring equipment; and to replace missing or erroneous readings with upwardly biased estimates.

The compliance period should be a year. Participants should have 60 to 90 days after the end of the compliance period to report their actual emissions and 30 to 60 days after the reporting deadline to submit the necessary allowances. The regulatory authority could set the same compliance period for all sources or allow participants to have different compliance periods.

The performance of the monitoring equipment, reported emissions (including adjustments for missing data) and the validity of the allowances or credits used for compliance must be verified by the regulatory authority or accredited independent experts each year. Compliance should be resolved within 6 to 12 months after the end of the grace period.

Borrowing should not be allowed. Banking should be allowed, but with "flow control" or discounting of banked allowances and credits if the quantity of banked allowances/credits becomes relatively large. A "safety valve" provision that allows the regulator to issue additional allowances at a relatively high pre-specified price should be included in the design.

To protect the environment and ensure that the non-compliance penalty is always higher than the price of an allowance/credit, the penalty should involve a reduction of the participant's allowance allocation for the next year equal to the excess emissions, assuming that allowances are distributed free. The non-compliance penalty should also include a significant financial penalty. Penalties should be automatic with provisions for appeal.

Since the trading program would cover about 95% of total SOx emissions, no provision should be made for the use of credits for reductions by sources outside the program. Most of the NOx emissions not covered by the trading program are from transportation sources. Thus, it is recommended that only NOx credits created by mobile source reductions in Alberta be accepted. Further, it is recommended that only a methodology approved by the U.S. Environmental Protection Agency, but adapted to Alberta if necessary, be accepted.

A GHG trading program should include provisions for the use of credits from Alberta sources for emission reductions by sources outside the program and for sink enhancement measures. GHG credits and allowances from other jurisdictions could also be accepted, but they should meet standards comparable to those set for Alberta emission reduction and sink enhancement actions. If another jurisdiction has a GHG emissions trading program, an efficient way to enable the use of credits or allowances from that jurisdiction is to link it with the Alberta trading program. This would enable participants in both programs to use allowances and credits from either program for compliance purposes.

If a national GHG emissions trading program is implemented, it is highly desirable that an Alberta GHG trading program be linked with, or transition to, the national program. If an Alberta and a national trading program are developed at the same time it would be better for the participants if both governments co-operated in the design of a single program that meets their respective goals. If an Alberta program is implemented first, it would be better for the participants subject to both programs, that the Alberta program be linked with or transition to a national program.

Recognition of early emission reductions at participating facilities should be addressed as part of the allowance allocation. Some Alberta entities have helped finance GHG emission reductions at sources that would not be covered by the trading program. Recognition of early GHG emission reductions at sources outside the trading program should be limited to those registered by GERT unless a link with other GHG trading programs allows recognition of other early reductions.

The implications of emissions trading for Power Purchase Agreements will need to be analyzed and resolved as part of the design of a trading program. The ideal solution would provide incentives to both the unit owner and the wholesaler to reduce emissions. The CO_2 offset requirements imposed on two new coal-fired generating stations will need to be integrated with a GHG emissions trading program.

If allowance allocations or baselines are tied to output, a physical measure of output is strongly preferred to an economic measure of output or a measure of input. Sectors consist of participants with the same unit of physical output. Achieving intersectoral equity is difficult because the sectors have different output measures. Options to address intersectoral equity exist for GHGs, but they do not work well for SOx and NOx. Although they have the same output, existing coal- and gas-fired generating units should be considered different sectors. All new coal- and gas-fired generating units should be treated as gas-fired units.

Implementation of emissions trading for SOx, NOx and GHG emissions by large industrial sources in Alberta will require resolution of many outstanding issues. Such a trading program could be implemented through the sectoral emission reduction agreements currently being negotiated as part of its climate change action plan. However, it would probably require much more preparation and coordination among agreements than is currently contemplated for the negotiation of greenhouse gas emission reduction agreements. Experience elsewhere suggests that an emissions trading program in Alberta is unlikely to begin operation prior to 2005 to 2007.

1. Introduction

1.1 Purpose

The purpose of this document was to assess the potential of emissions trading to help achieve broad air emission objectives for airborne pollutants and greenhouse gases efficiently and cost-effectively for the private and public sectors in Alberta. The document assessed the feasibility of emissions trading for sulphur oxides (SOx), nitrogen oxides (NOx), mercury (Hg) particulate matter (PM), volatile organic compounds (VOCs) and greenhouse gas emissions (GHGs) by large industrial sources in Alberta.

In the case of greenhouse gases the document assessed the feasibility of emissions trading to help achieve the emission reduction goals and objectives in the Alberta Government's climate change action plan: *Albertans & Climate Change: Taking Action*.

1.2 Emissions Trading

Emissions trading, more precisely trading of emission rights (allowances or credits), is a form of environmental regulation that allows a specified emissions target for a group of sources to be achieved at lower cost.[1] The participating sources and their collective emissions limit are determined by the regulatory authority. At the end of the compliance period, usually a year, each participant must submit allowances/credits equal to its actual emissions during the period to the regulatory authority. With compliance by all participants total emissions cannot exceed the emissions target.

Emissions trading enables the cost of meeting the collective emissions target to be reduced because sources able to cut their emissions at relatively low cost have a financial incentive to make larger reductions and to sell surplus allowances/credits to other participants. Sources facing relatively high costs to reduce their own emissions can save money by buying allowances/credits.

An effective emissions trading program requires:

- an emissions cap lower than the "business-as-usual" emissions;
- differences among participants in the cost of reducing emissions;
- enough participants to create a competitive market for allowances/credits;
- provisions to ensure that shifts in the location of emission reductions do not have adverse environmental or health consequences if the emissions have local impacts;
- accurate monitoring or calculation of actual emissions by each participant; and
- effective enforcement to ensure that each participant has allowances/credits to cover its actual emissions so that the emissions target is not exceeded.

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[1] For more information on emissions trading see: Haites, Erik, 2002. *An Emerging Market for the Environment: A Guide to Emissions Trading*, UNEP and UNCTD, available at: www.uneptie.org.

Emissions trading has been used in the United States for SOx, NOx, volatile organic compounds (VOCs), lead in gasoline, and ozone-depleting substances and in Denmark and the United Kingdom for GHGs.

1.3 Study Components and Approach

The *Alberta Environment Emission Trading Project, Major Feasibility Study, Preliminary Analysis and Discussion document* was prepared by a team of consultants led by Cheminfo Services. The analyses, conclusions and recommendations contained in this document have been prepared primarily by Margaree Consultants. The analyses, conclusions and recommendations rely on a substantial body of information and analysis contained in three supporting documents. These documents are Appendices to the Preliminary Analysis and Discussion document. The titles of the documents, contribution and project team firms primarily responsible are shown in the table below.

Supporting Documents and Project Team Consulting Firm Responsibilities

Titles	**Main Contribution to Major Feasibility Study**	**Project Team Consulting Firms Responsible**
Major Feasibility Study: Preliminary Analysis and Discussion Document (Main document)	Summary analyses, conclusions and recommendations regarding emissions trading programs for Alberta.	Margaree Consultants Inc.
APPENDIX A: MARKAL Results	Modeling the economic effects of emissions trading design options.	HALOA Inc.
APPENDIX B: Costs of Technologies to Reduce NOx and SOx Emissions From Industrial and Electric Power Generation Sources in Alberta	Capital and operating costs for individual technology options for major industrial and electric power generating facilities in Alberta.	Cheminfo Services Inc. Clearstone Engineering Inc.
APPENDIX C: Profile of Criteria Air Contaminants, Mercury and Greenhouse Gases Emissions in Alberta	Analysis of current and future potential emissions of criteria air contaminants, mercury and greenhouse gases for Alberta.	Cheminfo Services Inc.

The approach to assessing the feasibility of emissions trading for Alberta involved the following steps:

- establishment of a "business-as-usual" projection of emissions by Alberta sources (Appendix C);
- development and application of criteria to assess the suitability of substances for emissions trading (Part 2);
- for modeling purposes, specification of a range of emission reduction targets for those substances (Part 3);
- collection of detailed emissions data for facilities/equipment and estimation of costs for emission reductions achieved by technologies suitable for the Alberta sources (Appendix B);
- modeling to identify the measures that achieve the specified emission reduction targets at least cost (Appendix A and Part 3);
- modeling of alternative emissions trading program designs (Appendix A and Part 4); and

- preparation of recommendations relating to emissions trading in Alberta (Part 5).

1.4 Stakeholder Involvement

The project was managed by a Steering Committee that included representatives from Alberta Environment, Alberta Energy, and Climate Change Central.

The consultants met with stakeholders in October and December 2002. Attendance at the meetings was excellent -- over 60 stakeholders attended in October and over 100 in December. Stakeholders were given an overview of the project and an opportunity to provide input on the substances to be considered for emissions trading, targets to be analyzed, emission reduction technologies to be included, and emissions trading program designs to be modeled. Notes on the meetings were posted on Alberta Environment's Air Emissions Trading Project website and further comments were invited.

Emission reduction technologies were discussed with representatives of numerous Alberta firms. Some provided cost estimates and anticipated performance of technologies they had evaluated. Others confirmed or modified information compiled by the consulting team on the costs of reduction technologies that might be applied to their facilities.

In addition, members of the Steering Committee and the consulting team had extended meetings with representatives of industry and environmental groups with knowledge of emissions trading.

1.5 Acknowledgements

Members of the consulting team would like to express their appreciation to all of the individuals and organizations that provided input to the project. They are too numerous to mention individually, but include the following groups:

- the members of the project Steering Committee;
- representatives of the many companies that provided information on emission reduction technologies; and
- the stakeholders who attended the public meetings and/or provided comments.

While the input received from these numerous sources was a significant benefit to the document, the consulting team is solely responsible for the results of the project.

2. Substances Suitable for Emissions Trading

2.1 Criteria

This section assesses the suitability of emissions trading for sulphur oxides (SOx), nitrogen oxides (NOx), mercury (Hg), particulate matter (PM), volatile organic compounds (VOCs) and greenhouse gases (GHGs) emissions by large industrial sources in Alberta.

A substance is considered suitable for emissions trading by large industrial sources if:

- emissions by these sources are a significant share of total provincial emissions;
- their emissions are measurable and verifiable;
- the number of sources and distribution of emissions among these sources suggest a competitive market;
- participants have a variety of abatement options with different marginal costs;
- emissions trading does not raise environmental or health concerns; and
- participants have or can acquire the knowledge, competencies and culture needed for emissions trading.

Complete emissions data are not available for some individual sources in the province. Aggregate emissions are available for large sources in the cement, chemicals, electricity generation, upstream oil and gas, petroleum refineries, oil sands, and pulp and paper industries. The emissions of large sources in those sectors are used for the assessment although it is recommended that large sources in other sectors also be included in an emissions trading program.[2]

2.2 Share of Total Provincial Emissions

The purpose of emissions trading is to enable an aggregate emission reduction target to be achieved at lower cost. Emission reductions by the trading program participants can yield a substantial environmental benefit only if their combined emissions represent a significant share of the total emissions. If the emissions of the potential trading program participants are a small share of total emissions, policies focused on the sources that are responsible for most of the emissions are more likely to yield the desired environmental benefits.

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[2] Some emissions, such as SOx, NOx and mercury, depend upon the characteristics of the fuel and the combustion process and so can only be measured accurately in the emissions stream. Large sources often account for a substantial share of the total emissions of those substances. Hence, emissions trading programs focus on the emissions of large sources. Other emissions, such as the CO_2 emissions due to combustion of fossil fuels, can be calculated accurately from the fuel characteristics; the carbon content of the fuel in the case of CO_2 emissions. Hence, those emissions can be calculated accurately from the quantity of each fuel used and its carbon content, which is very consistent for most fossil fuels. Thus, fossil fuel CO_2 emissions could be regulated by limiting the carbon content of fuels used in the province or by limiting the greenhouse gas emissions (which include CO_2) of fossil fuel users. Alberta's climate change action plan proposes negotiation of limits on greenhouse gas emissions by large industrial sources.

The total provincial emissions and the emissions by large sources in the specified sectors are shown in Table 1. The table includes total particulate matter emissions (PMT) as well as emissions of particulate matter less than 10 microns in diameter (PM10) and less than 2.5 microns in diameter (PM2.5) since they raise different health concerns.[3] Note that the units for mercury and greenhouse gases are different than those for the other substances.

Table 1: Estimated Alberta Emissions by Source, 2010
(Estimates of NOx, SOx, GHG, Hg emissions by large sources in sectors considered for emissions trading from the MARKAL Base case)

	SOx (kt)	NOx (kt)	VOCs (kt)	PMT (kt)	PM10 (kt)	PM2.5 (kt)	Hg (kg)	GHGs (Mt)
Total emissions	561	851	2,256	6,878	2,032	327		
Natural sources	-	29	1,297	54	46	38		
Anthropogenic emissions*	561	822	960	6,824	1,986	289	1,000	254
Emissions from Large Sources in Sectors Considered for Emissions Trading from the MARKAL Base case								
Cement	3	6	-	1		-		2
Chemicals	-	19	14	2	2	1		14
Electricity generation	129	98	1	9	8	8	940	58
Conventional oil & gas	229	372	497	2	2	2		51
Petroleum refineries	12	5	1	1	1	1		6
Oil sands plants	169	157	280	32	18	11		57
Total large industrial**	545	657	793	47	31	23	940	188
Large industrial share***	97%	78%	35%	1%	2%	8%	94%	74%

Notes: kt = kilotonnes (1,000 tonnes), kg = kilogram, Mt = megatonnes (1,000,000 tonnes).
GHG expressed as CO_2-equivalent.
"-" = less than 0.5 kt, (or less than 0.5 kg for mercury).
* "Anthropogenic emissions" include PM emissions (dust) from vehicle traffic on paved and unpaved roads.
** Does not add to above "considered sources for emissions trading". Includes all sources from large industrial.
*** Approximate share of Total Emissions except for Hg and GHGs, which are shares of Anthropogenic emissions.

Conceptually, the emissions by large industrial sources should be related to total emissions in the relevant airshed. In practice this is impractical. The relevant airsheds are often difficult to define and may cover a geographic area much larger than the province.[4] Most large sources in the province are regulated by the provincial government. To implement an emissions trading program for an airshed larger than the province would require regulatory coordination across several jurisdictions. Where the relevant airshed is smaller than the province, the number of participants may be too small to create a competitive market for allowances/credits. Limits on the actual emissions of sources to prevent adverse local health and environmental impacts allows those concerns to be addressed in the context of a provincial trading program. In practice, then, an emissions trading program in Alberta is best implemented on a provincial scale.

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[3] The PM2.5 emissions are also included in the PM10 figures and the PM10 emissions are also part of the PMT totals.

[4] The relevant airshed for GHGs is the entire globe.

Emissions by large industrial sources are related to total emissions except for mercury and GHGs. Data on natural emissions of mercury are not available for Alberta.[5] In the case of GHGs the environmental concern is human-induced enhancement of climate change, which is a function of the anthropogenic emissions of greenhouse gases. Over half of the total VOC emissions are from natural sources. Both the natural and anthropogenic VOCs react with NOx to form ground-level ozone. In Alberta it is believed that ozone formation is generally limited by the NOx emissions. Then the main reason to limit VOCs is to control emissions of toxic VOCs. Direct regulation of specific toxic VOCs from relevant sources is more appropriate than emissions trading of VOCs as a group.

The emissions data suggest that SOx, NOx, Hg and GHGs are suitable candidates for emissions trading. Trading programs for all of these substances, except mercury, have already been implemented elsewhere. However, trading for mercury emissions has been proposed in the United States. Particulate matter is not a good candidate for trading because large industrial emitters contribute only a small portion of the total emissions in Alberta. VOCs are not a good candidate for emissions trading because of the low share of total emissions contributed by large industrial sources and the nature of the environmental impacts of VOC emissions in the province.

2.3 Emissions are Measurable and Verifiable

Each participant in an emissions trading program must submit allowances or credits equal to its actual emissions to the regulatory authority each year. It is important, therefore, that participants accurately measure their actual emissions and that these can be verified by the regulatory authority.

SOx and NOx emissions are formed during combustion of fossil fuels, and so must be measured in the emissions stream. Mercury emissions come from the fuel, mainly coal, but part of the mercury remains in the ash, so the emissions also must be measured in the emissions stream. Continuous emission monitors can measure SOx and NOx emissions, but such monitoring equipment is relatively expensive. Mercury emissions cannot be monitored on a continuous basis with reasonable accuracy at the present time.

Greenhouse gas emissions consist mainly of CO_2 emissions due to combustion of fossil fuels. But some processes in the cement, lime and chemical industries also generate emissions of CO_2 and other greenhouse gases. Greenhouse gas emissions by large industries can be measured using continuous emission monitors and can also be calculated from the fuel consumption and process parameters.

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[5] There are different species of mercury emissions with different health and environmental impacts.

Existing trading programs for SOx, NOx and GHGs have specified monitoring equipment or calculation procedures for different types and sizes of sources.[6] Methods for monitoring mercury emissions continuously with reasonable accuracy are not available at the present time. Adoption of existing proposals for emissions trading for mercury in the United States would lead to specification of equipment and procedures for monitoring those emissions by coal-fired electricity generators. Thus, SOx, NOx and GHGs meet this criterion and mercury may meet this criterion in the future.

2.4 Enough Sources to Create a Competitive Market

To minimize the cost of achieving the aggregate emission reduction, the price of an allowance or credit must be equal to the marginal cost of achieving the reduction. This condition should prevail in a competitive market, but will not be met if one (or a few) firms dominate.

A competitive market requires a "large" number of firms with no single or small group of firms large enough to affect the supply or demand. Based on the criteria the U.S. Department of Justice uses to assess the competitiveness impacts of mergers of firms in the same market, the market should have at least ten participants, the market share of the largest firm should be less than 30% and the combined market share of the four largest firms should be less than 65%.[7]

A multi-sector emissions trading program for large industrial sources in Alberta would likely have several hundred participants as can be seen from Table 2. Virtually all of the participants would have some SOx, NOx and GHG emissions. And it appears that no participant would be responsible for more than 15% of the total industrial emissions of any of these substances.

As can be seen from Table 1, electricity generators account for almost 95% of the mercury emissions that would be covered by a trading program. Three firms currently own the coal-fired units that are the source of these emissions, so the market share is well above the competitive market threshold of 65% for the four largest firms. Mercury does not meet the criterion for a competitive market. If an emissions trading program is established it could include mercury once monitoring equipment and procedures are available, but it is likely that most "trades" would be between units owned by the same firm.

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[6] In the U.S., federal programs require the use of continuous emission monitors for sources with large (>250 mm BTU/hr) boilers, but exempt peaking units (<10% utilization) and small emitters (<100 tons NOx/yr).

[7] The U.S. Department of Justice (US DOJ, 1997, section 1.5) assesses mergers of firms in the same market on the basis of their impact on concentration using the Herfindahl-Hirschman Index (HHI). The HHI is calculated as the sum of the squares of the market shares of the four largest firms. For example, if the four largest firms in a market had shares of 30%, 20%, 15% and 10% (a total of 75%), the HHI is 30*30 + 20*20 + 15*15 + 10*10 = 900 + 400 + 225 + 100 = 1,625. The Department considers markets with an HHI of less than 1,000 to be unconcentrated. In an unconcentrated market, the market share of the largest firm must be between 15% and 30% and the combined market share of the four largest firms must be between 35% and 65% and there must be at least ten participants.

Table 2: Number of Future Alberta Facilities/Units and Companies Potentially Involved in Emissions Trading

Sector	Number of Facilities	Number of Companies
Cement	2	2
Chemicals (major facilities)	~20	~15
Electricity generation	~55 units	~8
Upstream oil and gas	Hundreds or thousands*	Hundreds
Petroleum refineries	4	4
Oil sands plants	24	~20
Pulp mills	4	4
Note: * depending on detailed design.		

The number of firms in each of the industry sectors indicates that an emissions trading program limited to a single sector, except upstream oil and gas, would not have enough participants to create a competitive market.[8] The number of sources for SOx, NOx and GHG suggest that they should be able to meet the criterion for a competitive market if the program covers all large industrial sources in the province.

The allocation of allowances or specification of baselines will affect which sources are buyers and which are sellers. Hence, whether there are a few dominant buyers or sellers is affected by how allowances are allocated or baselines are specified. The trading pattern is assessed for each of the allocation options modeled in Part 4 to determine whether there are likely to be a few dominant buyers or sellers.

2.5 Abatement Options With Different Marginal Costs

The cost savings stem from differences among participants in the marginal cost of reducing a tonne of emissions. Those differences allow participants with low cost reduction opportunities to implement larger reductions and to sell surplus allowances or credits at a profit. And it allows participants with high cost reduction opportunities to save money by purchasing allowances/credits rather than implementing costly reduction measures themselves.[9]

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[8] The experience of other trading programs with a small number of participants in the same industry (Canadian CFC program, US large vehicle engine ABT program, Danish CO_2 program) is that trading is limited so the potential cost savings may not be fully realized.

With a variety of emission reduction options and participants from several industries it would be astonishing if there were no differences in marginal costs.[10] The experience elsewhere is that even in a single industry and a single control technology, costs vary among participants due to differences in the size, age and utilization of the plant, as well as other factors.

The cost data collected for emission reduction technologies indicate substantial differences in unit costs for each of the substances for Alberta sources. It was assumed, therefore, that this criterion would likely be met for SOx, NOx and GHGs based on the number and diversity of the participants. The assumption is confirmed by the modeling results, which show both buyers and sellers of SOx, NOx and GHG allowances/credits for each of the allocation options, indicating the existence of differences in marginal costs and hence potential savings from emissions trading.

2.6 Adverse Environmental or Health Impacts Due to Trading

Emissions trading limits the aggregate emissions of the participants, not the emissions of individual participants. Thus the emissions of one source could rise even though total emissions fall. And the emissions in a given region could rise due to the location of new sources, even if total emissions in the province decline. If a substance has local impacts, such developments could lead to adverse environmental or health consequences in the region where the emissions increase.

SOx emissions lead to acid deposition over a large geographic area. The environmental impacts depend upon the cumulative deposition. SOx emissions also lead to formation of fine particulate (PM2.5) in the atmosphere and so contribute to local respiratory problems. NOx emissions contribute to acid deposition and atmospheric formation of fine particulate. NOx and VOCs also react in the atmosphere to form ground-level ozone during the summer.[11] Ground-level ozone has a variety of adverse environmental and health impacts locally. The impacts of greenhouse gas emissions depend upon cumulative global emissions.

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[9] Participants with high cost reduction options usually achieve compliance by implementing some low cost measures and purchasing allowances/credits to cover their remaining emissions.

[10] It is possible, but unlikely, that the marginal cost is the same for many sources if they are subject to regulations that require them to implement the same emissions control technology. That is not the case because GHG emissions currently are not regulated and the SOx and NOx controls vary across sources.

[11] The chemical reactions are very complex and their effects are regionally specific. In general, ozone formation is effectively limited by either the NOx or the VOC emissions. In Alberta NOx emissions are believed to be the principal constraint on ozone formation. If that is correct, reducing VOC emissions would not reduce ozone formation. This is another reason for including NOx, but not VOC, emissions in a trading program.

Alberta currently has regulations designed to ensure that emissions by a given source do not result in adverse environmental and health impacts. Other jurisdictions have retained such regulations when a trading program is implemented and prohibit actual emissions from exceeding the level allowed by those regulations regardless of the quantity of allowances or credits held.

Analysis of the model results will indicate whether emissions of SOx or NOx are likely to increase in a particular region thus creating adverse environmental and/or health impacts. In any case, it is recommended that, if Alberta implements an emissions trading program, it retain regulations that limit actual emissions by trading program participants to protect local air quality. With those regulations as a "backstop" the trading program will not create adverse environmental or health impacts and this criterion will be met.

2.7 Participants Have the Necessary Skills

Emissions trading would be a new form of environmental regulation for participants in Alberta. To comply, and especially to achieve the potential cost savings, participants must have, or acquire the knowledge, competencies and culture needed. Some Alberta firms have participated in emissions trading pilot projects and/or have participated in some transactions. They may have sufficient competence now to participate in an emissions trading program. Other participants will need to acquire the necessary knowledge and skills.

Compliance with the requirements of an emissions trading program is not particularly difficult. Many participants simply implement emission reduction measures to reduce their actual emissions below their allowance allocation. This achieves compliance, but may not minimize costs. To minimize compliance costs a participant must forecast the price of allowances, then implement emission reduction measures whose average cost is less than this price and contract for the purchase (sale) of the remaining allowance requirements (surplus). Brokers and consultants are available to help sources with such analyses and the purchase or sale of allowances.

The trading program participants are large firms that should be able to develop or acquire the necessary skills. The value of their energy and/or raw material purchases is likely to be much larger than the value of their allowance transactions. In other jurisdictions where emissions trading has been introduced participants have been able to develop or acquire the necessary competence.[12] It is assumed that the participants in an Alberta trading program for SOx, NOx and GHG emissions could meet this criterion.

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[12] The evaluation of the RECLAIM program found that some participants had difficulty adjusting to a market-based system (U.S. Environmental Protection Agency, 2002a, p. 21).

2.8 Conclusions

Based on the criteria adopted, SOx, NOx and GHG emissions by large industrial sources in Alberta appear to be well suited to a province-wide emissions trading program. Model results confirm that:

- the marginal costs of emissions reductions vary across sources so that cost savings are possible with emissions trading;
- the proposed allocation of allowances does not create a few large buyers or sellers; and
- emissions trading is unlikely to increase SOx or NOx emissions by sources in a particular region enough to create environmental or health concerns.

Regardless of the model results, it is recommended that Alberta retain regulations that limit actual SOx and NOx emissions by trading program participants to protect local air quality if it implements an emissions trading program. This would provide an additional level of certainty about the environmental integrity of the program.

Alberta's climate change action plan assumes that emissions trading is a feasible approach to achieving its GHG emission reduction target for industrial sources. The feasibility of emissions trading for large industrial sources is confirmed. The action plan proposes that the GHG emission reduction target be implemented through sectoral agreements. To implement an efficient emissions trading program in this way requires that the sectoral agreements include common provisions for emissions trading that address the issues discussed in Part 5.

Mercury is not suitable for emissions trading in Alberta because three electricity generators dominate total emissions, so there would not be a competitive market for the allowances and because currently available monitoring systems can not measure mercury emissions continuously. If a mercury emission reduction target is established for coal-fired electricity generators, mercury emissions by these sources could be added onto a trading program for SOx, NOx and GHG emissions once suitable monitoring systems are available. However, most trades in the mercury market probably would be transfers among units with the same owner.[13]

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[13] Other industrial sources of mercury emissions could be allowed to opt-in to the trading program or to generate credits for emission reductions achieved. This would encourage them to participate if they have low cost emission reduction opportunities. Mandatory participation by other industrial sources would leave them vulnerable to oligopolistic pricing of allowances if their internal emission reduction options are relatively costly. Limiting coverage to the electricity generators would cover about 95% of the total emissions.

3. Modeling Emission Targets

3.1 Introduction

An emissions trading program requires a limit on the total emissions of the participants that is lower than their "business-as-usual" emissions. Since SOx, NOx and GHGs are recommended for inclusion in the trading program, limits lower than "business-as-usual" emissions of the participants are needed for all of those substances. Because adoption of technologies to lower emissions of one of the substances can increase or reduce emissions of the others, combinations of limits must be analyzed. Modeling is used to identify the lowest cost actions to meet several combinations of emissions targets.

3.2 Emission Targets

Alberta's climate change action plan sets an objective of reducing greenhouse gas emissions relative to Gross Domestic Product (GDP) by 50% from the 1990 level by 2020. The action plan implies an objective of 218 $MtCO_2e$ of GHG emissions in 2020, and an interim target equivalent to 238 $MtCO_2e$ in 2010.[14] These totals are divided between large industrial sources (178 $MtCO_2e$ in 2010 declining to 158 $MtCO_2e$ in 2020 and other (transportation, residential, commercial, etc.) sources (56 $MtCO_2e$ in 2010 rising to 60 $MtCO_2e$ in 2020) for modeling purposes.[15] The climate change action plan also indicates that participants will be allowed to use credits from emission reduction and sequestration actions by other sources and allowances from other GHG trading programs for compliance. These options are modeled by assuming that an unlimited supply of GHG allowances/credits is available at a price of $10/t CO_2e in 2010 rising to $16 in 2020.[16]

Alberta currently does not have long-term emission targets for SOx, NOx or mercury. Alberta has followed the principles of "keeping clean areas clean" and "continuous improvement" in managing air emissions by industrial and other sources. Alberta currently has good air quality relative to national and international standards for ambient SOx and NOx concentrations. Thus the principle of "keeping clean areas clean" would allow total emissions to remain at current levels. Implementation of the "continuous improvement" principle requires new and existing sources to adopt best available control technologies over time. The net impact of this approach on total emissions depends on the reductions achieved by the control technologies implemented and the increased emissions due to new sources.

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[14] MARKAL estimates the 2010 reduction target for GHG emissions as 234 megatonnes. This is 1.7% below Alberta's target of 238 Mt implied by its action plan. This difference is due to MARKAL model calibration. Year 2020 calibration differences are zero. These calibration differences are negligible and do not materially affect the results of this document.

[15] The limit on the transport sector (which would not be part of the trading program) is likely to affect the demand for transportation fuels, which will affect emissions by petroleum refineries (which would be part of the trading program). Thus, limits on emissions outside the trading program affect the trading program. These effects are captured by the MARKAL model.

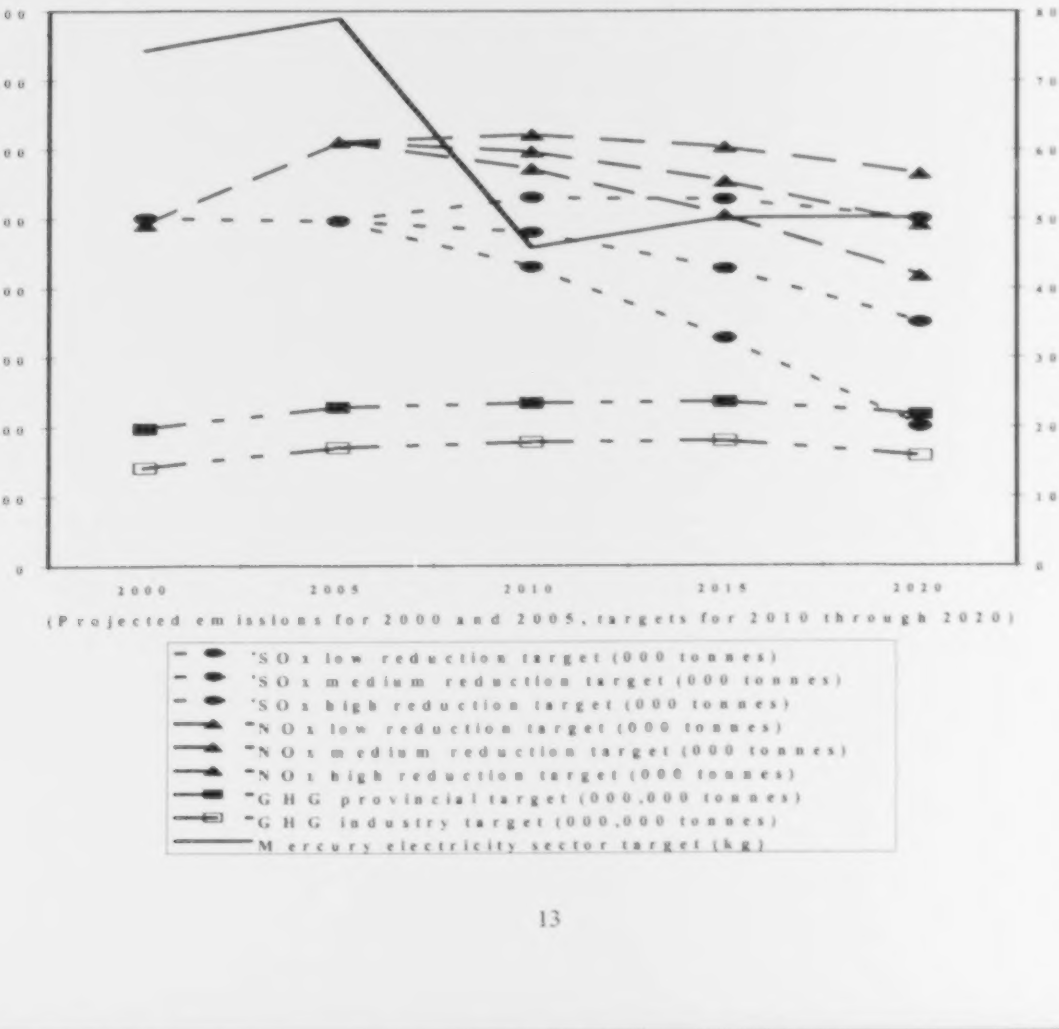
[16] Both prices are in year 2000 Canadian dollars.

Three targets are analyzed for emissions of SOx (0%, 30% and 60% reduction from 2000 emissions in 2020) and NOx (+15%, 0% and -15% from 2000 emissions by 2020) by large industrial sources.

The Clean Air Strategic Alliance (CASA), which is currently discussing options for managing the emissions of electricity generators, may recommend that mercury emissions by these sources be reduced. The need to reduce mercury emissions could affect the options selected for managing SOx, NOx and GHG emissions, so a mercury target must be included to properly model least-cost compliance strategies. It is assumed that coal-fired electricity generators are required to reduce their mercury emissions by 50% from projected levels beginning in 2010. Each coal-fired generating unit must reduce its own mercury emissions; reductions are not tradable.

The emission targets analyzed are shown in Figure 1. The targets for SOx, NOx and mercury are not regulatory proposals. They are simply arbitrary points in the range of possible emission reductions that are used to analyze how costs change as emission targets become more stringent. The combinations of emission reduction targets modeled are discussed below. A brief overview of the model used is presented first.

Figure 1: Emission Targets



3.3 The Alberta MARKAL Model

The Alberta MARKAL model is a dynamic, technology-explicit representation of all sectors of the Alberta economy, with emphasis on sectors that consume or produce energy. The model computes a partial equilibrium on energy markets based on the maximization of net total surplus (profits) over the 2000-2020 period.

The Alberta MARKAL model has a detailed representation of industrial processes existing in Alberta, but without representation of ownership, except in the electric power generating (EPG) sector. In the EPG sector each existing or planned generating unit is individually represented with its own investment/retirement dynamics.[17] Future expansions not yet announced are represented by generic technologies such as: pulverized coal, integrated coal gasification combined cycle, single cycle gas turbine, combined cycle gas turbine (with or without cogeneration of steam), wind turbine, solar, and biomass.

MARKAL also represents the emissions and reduction options of each large facility in Alberta, for the following industries: chemicals (27 processes in a dozen facilities), cement (2 facilities, 3 kilns), pulp and paper (4 facilities), oil refining (4 facilities), and wood products (approximately 20 facilities grouped as seven entities). The hundreds of facilities in the upstream oil and gas sector are modeled as three sub-sectors: oil sands (all types), gas production and processing (including transmission), and conventional oil production.[18] GHG emissions (and reduction opportunities) are also represented for the transportation, residential, commercial, other industry, and other emissions sectors.

The Alberta economy is linked to the rest of North America and the world. Results from the North American MARKAL model were used to embody these links in the Alberta MARKAL model as follows:[19]

- unlimited exports of bitumen, crude oil and natural gas are allowed at the North American market prices. Moderately higher costs in Alberta reduce profits, but do not change the quantities exported because the market prices are set by supplies from other regions. However, if production costs rise significantly, production and exports would decline;
- exports and imports of electricity are fixed at the levels in the North American equilibrium. Electricity prices rise if costs increase; and
- demand for the output of the cement, chemicals and pulp and paper sectors has a price elasticity of -4.0 (a relatively large reduction in demand if the price increases).

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[17] The EPG sector includes six announced new units: Fording 1 and 2, Genesee 3, Keephills 3 and 4, and AES. The first five units are coal-fired and the last is a combined cycle gas turbine unit. The recently announced retirement dates for some Wabamun units also have been implemented. The life of other existing coal fired units may be extended if this is cheaper than adding a new generating unit.

[18] The oil sands subsector includes all 24 existing and proposed projects identified in the High forecast of the National Energy Board with a total production reaching .82 MBOD in 2015 and stable thereafter.

[19] The results are for Base case I as specified in the National Climate Change Process. The Alberta model provides more emissions detail than is available in North American MARKAL.

For each facility (or each sub-sector in the case of upstream oil and gas), a number of options for reducing SOx, NOx and GHG emissions are available in the model. Each option is described in terms of its impact on the SOx, NOx and GHG emissions, capital and operating costs, and energy requirements. The emission reduction achieved by an option is directly proportional to the activity of the facility or sub-sector. Many options have an impact on emissions of more than one substance.[20]

Each emissions cap is imposed on the affected sources for the relevant periods. The model is then run to find a new equilibrium that respects these caps. The model finds the equilibrium that maximizes the net present value of surplus (profit) over the 2000-2020 period; this is equivalent to achieving the caps at minimum total net cost. The actions implemented to reduce emissions increase production costs, which may lead to lower output and/or profits.

3.4 Alternative Sets of Emissions Targets

To assess how costs change with the stringency of the emissions targets, the following cases are modeled.

1. Base case: This case assumes no restrictions on any emissions beyond existing regulations. The existing and future technologies are provided with their "business as usual" emission factors as of 2002. The model's assumptions are those used in the Base case of the National Climate Change Process, defined in 2002 by the Analysis and Modeling Group. It reflects the National Energy Board's High forecast (24 projects) for the oil sands sector, middle-of-the-road economic growth in all other sectors of the Alberta economy, as well as a moderate world crude oil price. The Base case serves as the reference against which the costs of meeting alternative emissions targets are compared.

   The output growth projected for an industry may be lower in the emissions control cases than in the Base case, due to the response of the industry to price changes resulting from emission reduction actions. In particular, specific projects that have been announced but not yet been built (such as power plants and oil sands projects) are part of the Base case, but may not be included in an emissions control case because changes in costs or demand make them unprofitable.

2. GHG case: Provincial GHG emissions are constrained to 234 $MtCO_2e$ in 2010 and 218 $MtCO_2e$ in 2020 consistent with the target specified in Alberta's climate change action plan. The cap for large industrial sources in the trading program declines from 178 $MtCO_2e$ in 2010 to 158 $MtCO_2e$ in 2020. Trading program participants are allowed to buy/sell allowances from/to an external market at \$10/t CO_2e in 2010 rising to \$16 in

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[20] An option may reduce emissions of all substances by different percentages or reduce emissions of some substances and increase emissions of others.

2020.[21] GHG emissions by other sources (transportation, residential, commercial, etc.) are capped at 56 $MtCO_2e$ in 2010 rising to 60 $MtCO_2e$ in 2020 but with no opportunity to trade. Mercury emissions by each electricity generator are reduced by 50% from Base case levels beginning in 2010 (a total of 458 kg in 2010 rising to 501 kg in 2020) with no trading of mercury permits.

3. Low SOx, NOx reductions: The SOx target for all industrial sources is equal to 2000 emissions in 2020, the NOx target for industrial sources is a 15% increase from 2000 emissions in 2020, the GHG and mercury emissions targets are as in Case 2. SOx and NOx targets for 2010 and 2015 are obtained by assuming that reductions from "business-as-usual" are linearly interpolated from 2005 to 2020.

4. Medium SOx, NOx reductions: The SOx target for all industrial sources is a 30% reduction from 2000 emissions in 2020 and the NOx target for all industrial sources is equal to 2000 emissions in 2020, using linear interpolation of reductions from 2005 to 2020 to get the 2010 and 2015 targets. The GHG and mercury targets are the same as for Case 2.

5. High SOx, NOx reductions: The provincial SOx target for industrial sources is a 60% reduction from 2000 emissions in 2020 and the provincial NOx target for industrial sources is a 15% reduction from 2000 emissions in 2020, using linear interpolation of reductions from 2005 to 2020 to get the 2010 and 2015 targets. The GHG and mercury targets are the same as for Case 2.

These 5 cases are not focused on emissions trading or permit allocations; their purpose is solely to gain insight into the cost of different emissions targets and the interaction among the impacts of the targets for different substances. MARKAL identifies the least-cost combination of measures to meet the emissions targets specified for each case.

3.5 Costs of Meeting the Alternative Emissions Targets

A greenhouse gas target (Case 2) leads to implementation of measures that also reduce SOx and NOx emissions. Indeed, the GHG target leads to sufficient reduction of SOx emissions to meet the low SOx target, resulting in a zero marginal cost for SOx reductions in Case 3. Conversely, SOx and NOx targets induce much smaller reductions in GHG emissions as can be seen by comparing the GHG emission reductions across Cases 3, 4 and 5. These results suggest that the GHG target will have a more significant impact on firms' compliance strategies than the SOx and NOx targets. The costs of meeting the alternative emissions targets are summarized in Table 3, below.

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[21] These prices are in year 2000 Canadian dollars.

Table 3: Costs of Meeting Alternative Emissions Targets

	Total Cost[a] (millions of 1995$)	Cumulative emission reductions[b]				Marginal cost of emission reductions[c]			
		GHGs ($MtCO_2e$)	SOx (kt SO_x)	NOx (kt NO_x)	Hg (kg)	GHGs ($/t$CO_2e$)	SOx ($/t SO_x)	NOx ($/t NO_2)	Hg[d] ($000/kg)
Case 2	$50	490	1,112	362	8,925	$9 $12 $15			$93 $93 $93
Case 3	$61	490	1,115	1,334	8,925	$9 $12 $15		$61 $61 $61	$93 $93 $93
Case 4	$110	505	1,962	2,071	8,985	$9 $12 $15	$17 $128 $218	$61 $61 $1,141	$93 $93 $93
Case 5	$349	520	3,462	2,808	9,125	$9 $12 $15	$218 $415 $1,795	$61 $354 $1,141	$93 $93 $93

Notes:

a) The total cost is the net present value in 2000 of costs incurred over the period 2000 through 2020 discounted at 10% per year net of inflation. All figures are in 1995 Canadian dollars.

b) Cumulative emission reduction is calculated as the sum of the reductions from Base case emissions for 2010, 2015 and 2020 multiplied by 5.

c) Marginal costs are for 2010, 2015 and 2020 respectively in 1995 Canadian dollars.

d) Since mercury is not traded the marginal cost can be different for each coal-fired generating unit. The marginal cost of $93,000/kg is that of the mercury control technology implemented by most units. Depending upon the case, between one and three coal-fired generating units are able to meet their mercury limits at a lower marginal cost in 2020.

Figure 2 illustrates that total costs rise exponentially as the SOx and NOx targets become more stringent.[22] However, even the most stringent set of targets, Case 5, has a total cost of about 0.05% of the value of industrial output of covered sectors over the same period.

The MARKAL cost estimates must be interpreted with care. The model estimates the present value in 2000 of the net cost to Alberta society of meeting a specified emissions targets at the lowest cost over the period 2000 through 2020 assuming future developments are known with certainty. The cost estimates can be, and are, used to compare different sets of emissions targets and different options for distribution of allowances.

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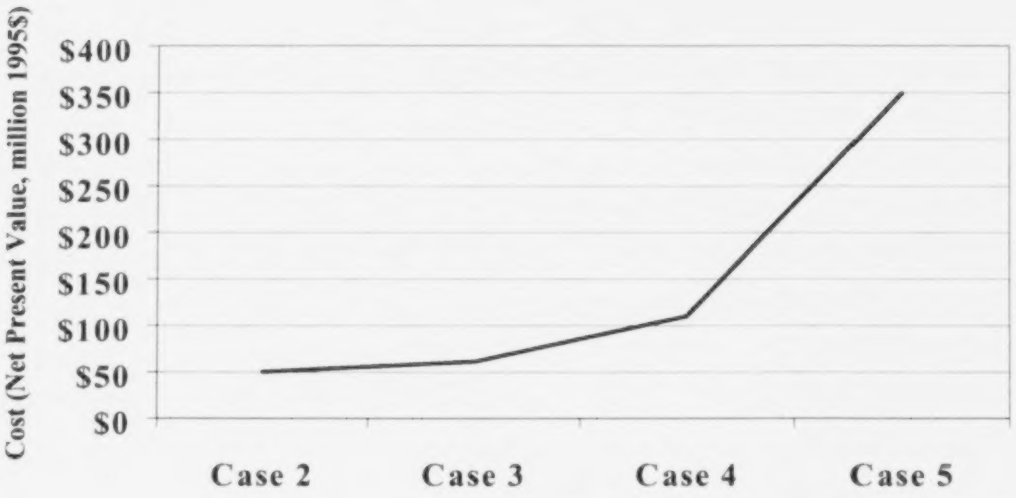
[22] Alberta industry is a net seller of GHG permits (3.5 to 4.0 Mt CO_2e) in 2010 and a net buyer (0.3 to 2.3 $MtCO_2e$) in 2015 and (15 to 19 $MtCO_2e$) in 2020 in the above cases.

Figure 2: Cost of Meeting Selected Targets



Comparing the cost calculated by MARKAL with the estimated cost of implementing an emission reduction measure is complex. The cost of implementing an emission reduction measure is the extra (incremental) capital cost and operating cost of the measure. This should be the same for a proposed installation and for the model, although the costs for a specific installation may differ from the "typical" costs used by the model.[23] The model implements only the measures needed to achieve the emissions targets at the lowest cost. The model credits cost savings due to emission reduction actions, such as lower energy costs due to energy-efficiency measures, against the costs incurred to implement the emission reduction measures. The model also credits higher revenues due to price increases against the costs incurred to implement the emission reduction measures. Finally, the model's cost takes into account variations in outputs of the various sectors, which have a direct impact on sectoral revenues.

The net cost calculated by the model is the present value in 2000 of incremental costs and cost savings that occur over the entire period from 2000 through 2020. Since the emissions targets are assumed to take effect in 2010, most of the emission reduction measures are implemented in 2010 or later. When the cost of a measure implemented in 2010 is discounted to 2000 at 10% per year, its present value is less than 40% of the cost in 2010. In addition, costs are expressed in 1995 dollars, which means they are about 20% lower than if expressed in 2003 dollars. As a result, if the cost of an emission control measure adjusted for inflation remains constant until 2010 when it is implemented, the reported present value is less than one-third of that amount. Thus, even when the same estimates of the costs of implementing emission reduction measures are used, the cost figures reported by the model may appear much lower.

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[23] Costs already incurred (sunk costs) are ignored, even though the firm may still be paying off associated debt, because the sunk costs should not affect decisions about future actions.

3.6 Emission Reductions by Industry Sector

MARKAL identifies the actions that meet the emission reduction targets at least cost. Some industry sectors have more low cost reduction options than others. Table 4 shows the percentage reduction from Base case emissions by substance for each industry sector to meet the alternative targets.

Table 4: Emission Reductions by Industry Sector

Industry Sector		**GHG**		**SOx**		**NOx**	
		2010	**2020**	**2010**	**2020**	**2010**	**2020**
Cement	Case 2	-39%	-50%	-37%	-50%	-37%	-50%
	Case 3	-39%	-50%	-37%	-50%	-37%	-50%
	Case 4	-39%	-50%	-37%	-57%	-37%	-71%
	Case 5	-39%	-50%	-44%	-87%	-37%	-71%
Chemicals	Case 2	-22%	-34%	0%	0%	-22%	-34%
	Case 3	-22%	-34%	0%	0%	-32%	-43%
	Case 4	-22%	-34%	0%	0%	-32%	-52%
	Case 5	-22%	-34%	0%	0%	-32%	-52%
Electricity Generation	Case 2	-17%	-21%	-10%	-15%	-17%	-19%
	Case 3	-17%	-21%	-10%	-15%	-27%	-30%
	Case 4	-17%	-25%	-10%	-28%	-26%	-44%
	Case 5	-18%	-27%	-10%	-92%	-28%	-47%
Natural Gas Production	Case 2	-11%	-17%	-23%	-27%	+1%	+1%
	Case 3	-11%	-17%	-23%	-27%	-4%	-27%
	Case 4	-11%	-17%	-24%	-72%	-12%	-41%
	Case 5	-12%	-17%	-46%	-79%	-19%	-41%
Oil Production (Conventional)	Case 2	-2%	-2%	0%	0%	+4%	+4%
	Case 3	-2%	-2%	0%	0%	+4%	+4%
	Case 4	-2%	-2%	0%	0%	+4%	-1%
	Case 5	-2%	-2%	0%	0%	+4%	+1%
Oil Refining	Case 2	-10%	-14%	-3%	-3%	-3%	-3%
	Case 3	-10%	-14%	-3%	-3%	-3%	-3%
	Case 4	-10%	-14%	-3%	-36%	-3%	-3%
	Case 5	-10%	-14%	-36%	-56%	-3%	-3%
Oilsands	Case 2	0%	-8%	0%	0%	0%	0%
	Case 3	0%	-8%	0%	0%	0%	0%
	Case 4	0%	-8%	0%	0%	0%	-2%
	Case 5	0%	-8%	0%	-27%	0%	-44%
Pulp and Paper	Case 2	-16%	-23%	-10%	-20%	-10%	-20%
	Case 3	-16%	-23%	-10%	-20%	-10%	-20%
	Case 4	-16%	-23%	-10%	-20%	-10%	-39%
	Case 5	-16%	-23%	-10%	-65%	-10%	-39%
All Industries Covered	Case 2	-10%	-16%	-12%	-15%	-3%	-4%
	Case 3	-10%	-16%	-12%	-15%	-7%	-19%
	Case 4	-10%	-18%	-12%	-36%	-10%	-30%
	Case 5	-10%	-18%	-21%	-63%	-14%	-40%

Conventional oil production implements virtually no SOx, NOx or GHG reductions. Oil sands facilities only reduce their SOx and NOx emissions in 2020 for the most stringent targets (Case 5). Oil refineries reduce their GHG emissions by about the same percentage as the industry average, but make virtually no NOx or SOx reductions except for SOx emissions in Cases 4 and 5.

Large reductions of SOx, NOx and GHG emissions occur in the cement, electricity generation, natural gas and pulp and paper industries in all cases. In addition, the chemical industry, which has low SOx emissions, makes large NOx and GHG reductions.

3.7 Impact of Alternative Targets on Industry Output

Emission reduction actions generally raise production costs and so lower demand and affect profits. The output impacts are shown by industry sector in Table 5. Oil and gas production levels do not decline as a result of the emissions targets. North American prices are determined by suppliers from other regions and the costs of Alberta producers do not rise enough to make them uncompetitive. Indeed, exports rise slightly because the emission reduction targets reduce provincial demand for oil and gas leaving more for export. The lower provincial demand is reflected in slightly lower output growth for oil refineries from 2000 through 2010.

Electricity output grows at a lower rate than in the Base case between 2000 and 2015 and then at a higher rate. There is little difference in the impact on output growth for the different emissions targets. However, this disguises an increase in gas-fired generation and cogeneration and a decrease in coal-fired generation that become more pronounced as the SOx and NOx targets become more stringent. These impacts affect mainly new capacity. New coal-fired capacity in Cases 2 - 5 drops to 2.9 TWh from 19 TWh in the Base case, barely enough for one of the five planned coal-fired units. Natural gas captures over 80% of the new generating capacity in Cases 2 - 5.

Non-energy industries typically experience a significantly lower growth rate, or a decline, in output between 2005 and 2010. The growth rates usually recover between 2010 and 2015, but are still lower than in the Base case. With a few exceptions, including cement and other manufacturing, growth rates during 2015 to 2020 are close to those in the Base case. Table 5 includes impacts on the output of the mining and other manufacturing industries because the GHG emission target affects them even though they are not part of the emissions trading program.

Table 5 indicates that all of the emissions targets analyzed (Cases 2 - 5) have virtually the same impact on output. This indicates that it is the actions needed to meet the GHG target (Case 2) that are the main determinant of the impact on output. Adding progressively more stringent SOx and NOx targets (Cases 3, 4 and 5) has virtually no impact on output. This is because the main options for reducing GHG emissions involve increased energy efficiency and fuel switching, which affect production processes. SOx and NOx emissions, in contrast, can be reduced by control technologies, which increase costs but do not change the production process.

Table 5: Output Impacts by Industry Sector

Industry Sector		Output Growth Rate (percent per year)			
		2000-2005	2005-2010	2010-2015	2015-2020
Cement	Base case	2.16%	1.29%	-0.29%	1.30%
	Cases 2 - 5	-2.61%	-3.00%	-3.53%	0%
Chemicals	Base case	3.00%	2.72%	3.38%	2.76%
	Cases 2 - 5	3.00%	-2.24%	0.39%	2.23%
Electricity Generation	Base case	2.94%	1.35%	1.51%	0.79%
	Cases 2 - 4	2.77%	-0.03%	1.07%	0.93%
	Case 5	2.77%	-0.03%	1.12%	1.01%
Natural Gas Production	Base case	4.09%	-0.51%	-0.03%	-0.13%
	Cases 2 - 5	4.09%	-0.51%	-0.03%	-0.13%
Oil Production (Conventional)	Base case	-1.04%	-0.89%	-0.64%	-1.92%
	Cases 2 - 5	-0.97%	-0.90%	-0.64%	-1.96%
Oil Refining	Base case	-1.35%	0.35%	4.31%	0.62%
	Cases 2 - 5	-1.56%	0.13%	4.29%	0.64%
Oilsands	Base case	14.92%	8.87%	1.62%	0%
	Cases 2 - 5	14.91%	8.77%	1.66%	0%
Pulp and Paper	Base case	1.25%	1.24%	1.12%	1.15%
	Cases 2 - 5	1.25%	-0.87%	-1.23%	1.15%
Mining	Base case	2.78%	1.98%	2.48%	2.54%
	Cases 2 - 5	2.78%	0.61%	2.73%	2.78%
Other Manufacturing*	Base case	0.70%	0.57%	0.53%	0.52%
	Cases 2 - 5	0.51%	0%	0%	0.02%
Note: * Includes wood products					

3.8 Impact of Alternative Targets on Industry Profits

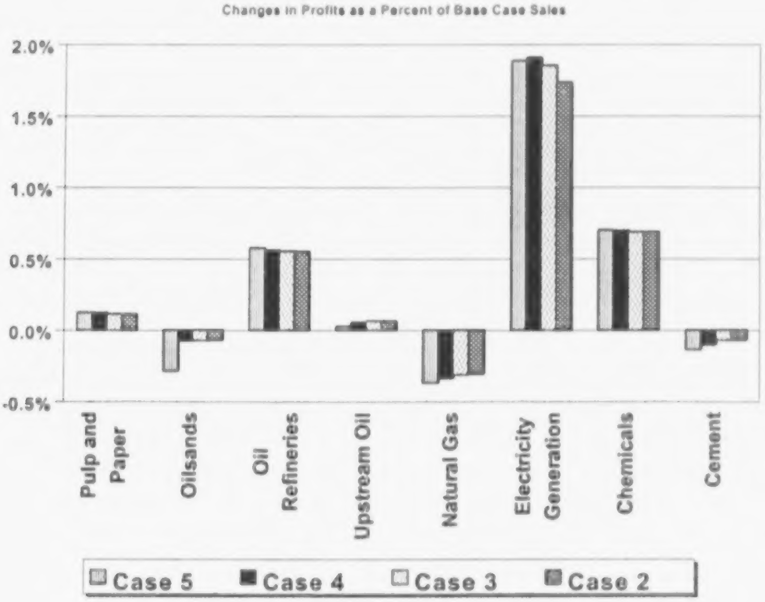
Since the costs and revenues of these targets differ, the cost differences will be reflected in profits. The model calculates profits as revenues minus costs in the year in which they occur, with no accounting adjustments such as depreciation. The present value of the profits is then calculated for the period analyzed (2000 - 2020). Profits are calculated for industry sectors because individual firms are not represented in the model, but profits would vary across firms in the same industry.

The model calculates the change in profits; revenue minus costs in the Base case compared with revenue minus costs for the emissions target case. The change in profits is expressed as a percentage of sales to facilitate a comparison of the impacts across industry sectors. Profits are often lower when the emissions trading program begins and rise after the emission reduction actions have been implemented. The impacts on profits by industry are shown in Figure 3, below.

Figure 3 shows that profits ***increase*** in some industries including chemicals, electricity generation, oil refineries, and pulp and paper. This results from two causes:

- For oil refining and electricity, the demand is relatively "inelastic" which means that the price and revenue may increase even if production declines. The model assumes that these industries are competitive and sets the price equal to the marginal cost. Compliance with the emissions target increases the marginal cost and hence the price, the total revenue and profits.
- For industrial sectors where the demand is "elastic" (such as chemicals and pulp and paper), the profit increase is due to a combination of two factors: a) cost savings due to "no regret" emission reduction actions where the reduction in energy costs exceeds the cost of the emission reduction measure, and b) cost savings due to lower output (only the output of the least profitable processes is reduced). The "no regret" emission reduction actions are not incorporated into the Base case because they are emission reduction measures added as part of this project.

Figure 3: Impacts on Profits by Sector



As expected, profits ***decrease*** in other sectors as a result of the costs associated with the emission reduction actions. This is the case for cement, natural gas, and oil sands. Conventional oil has lower profits in 2010 and 2015 and higher profits in 2020.

Profits are slightly affected in 2005 even though the targets do not come into effect until 2010 because sources begin to implement reduction measures in advance of the compliance period. It is not possible to apportion the profit impacts to the different emissions since actions to reduce emissions of one substance affect emissions of the other substances.

3.9 Impact of Alternative Targets on Regional Emissions

The only region where emissions rise relative to 2000 levels is Census Region 16, the Fort McMurray region where oil sands developments are concentrated. Oil sands output is expected to increase rapidly leading to SOx and NOx emissions increases of 53% and 169% respectively from 2000 by 2020 in the Base case. As noted earlier, oil sands make virtually no SOx and NOx reductions in Cases 2, 3 and 4. In Case 5, SOx and NOx emission reductions are implemented in 2020, but total SOx and NOx emissions are still 20% and 68% higher respectively than in 2000.

Alberta Environment currently has no basis for concluding that the 2020 Base case SOx and NOx emissions in Region 16 would cause unacceptable health or environmental impacts. However, the Cumulative Effects Management Association (CEMA) is currently conducting studies and analyses that will guide future decisions regarding a SOx and/or NOx cap for the Ft. McMurray area.

3.10 Conclusions

A greenhouse gas target leads to implementation of measures that also reduce SOx and NOx emissions. SOx and NOx targets induce much smaller reductions in GHG emissions. These results suggest that the GHG target will have a more significant impact on firms' compliance strategies than the SOx and NOx targets.

The cost of meeting emission reduction targets rises exponentially as the targets become more stringent. The cost of the most stringent set of targets analyzed is about 0.05% of the value of industrial sales over the period. The residential, commercial and transportation sectors also bear costs due to the emissions targets in the form of higher bills for fossil fuels and electricity.

Some industry sectors have more low cost emission reduction opportunities than others. This means that marginal costs differ across sources, which means that emissions trading can lower the cost of achieving an aggregate emission reduction target.

Implementing the least-cost emission reduction measures leads to large emission reductions by some industries and no reductions by others. Large reductions of SOx, NOx and GHG emissions occur in the cement, electricity generation, natural gas and pulp and paper industries. The chemical industry, which has no SOx emissions, makes large NOx and GHG reductions. Oil refineries make GHG reductions, but virtually no NOx or SOx reductions. Oil sands facilities only reduce their SOx and NOx emissions in 2020 under the most stringent target. Conventional oil production implements virtually no reductions.

The emissions targets analyzed do not affect oil and gas output; indeed exports rise slightly due to lower provincial demand. Non-energy industries typically experience a significantly lower growth rate for, or a decline in, output between 2005 and 2010. The growth rates usually recover between 2010 and 2015, but are still lower than in the Base case.

The GHG target is the main determinant of the impact on output. Adding progressively more stringent SOx and NOx targets has virtually no impact on output. This is because the main options for reducing GHG emissions involve increased energy efficiency and fuel switching which affect production processes. SOx and NOx emissions, in contrast, can be reduced by control technologies, which increase costs but do not change the production process.

Profits are higher in the chemicals, electricity generation, oil refineries, and pulp and paper sectors and lower in the cement, natural gas, and oil sands sectors relative to the Base case. Conventional oil has lower profits in 2010 and 2015 and higher profits in 2020. Individual firms are not represented in the model, but it is likely that profit impacts would vary across firms in the same industry.

Higher profits are possible with an emissions target when:

- the demand is relatively "inelastic" (oil refineries and electricity generation), which means that the price and revenue may increase even if production declines. The model assumes that these industries are competitive and sets the price equal to the marginal cost. Compliance with the emissions target increases the marginal cost and hence the price, the total revenue and profits.
- the demand is "elastic" (such as chemicals and pulp and paper), the profit increase is due to a combination of two factors: a) cost savings due to "no regret" emission reduction actions where the reduction in energy costs exceeds the cost of the emission reduction measure, and b) cost savings due to lower output (only the output of the least profitable processes is reduced). The "no regret" emission reduction actions are not incorporated into the Base case because they are emission reduction measures added as part of this project.

Implementing the least-cost emission reduction actions reduces emissions from 2000 levels in all regions except Region 16 where the oil sands expansion occurs. Alberta Environment currently has no basis for considering that the 2020 Base case SOx and NOx emissions in Region 16 would cause unacceptable health or environmental impacts. However, the Cumulative Effects Management Association (CEMA) is currently conducting studies and analyses that will guide future decisions regarding a SOx and/or NOx cap for the Ft. McMurray area.

4. Distribution of Allowances

4.1 Introduction

Emissions trading creates financial incentives to implement the least-cost emission reduction measures -- the measures that yield the results presented in the previous section. The analysis in the previous section assumes that the costs of the measures implemented are borne by the source that implements the measure. The resulting distribution of costs -- increased profits in some industries and lower profits in others -- is likely to be considered unfair by at least some sources.

Traditional environmental regulations impose requirements, and hence costs, on all affected sources. This increases the total cost because the required measures will not be limited to the least-cost measures across all sources. And the distribution of output and profit impacts across the affected sources may still be considered unfair by some sources.

Emissions trading deals with equity through the distribution of allowances (emission rights) or establishment of baselines. The analysis in the previous section shows that if the least-cost measures are implemented, the cement industry implements large emission reductions and incurs lower profits while oil refineries make relatively small emission reductions and enjoy higher profits. Assume that allowances are distributed (or baselines are set) so that oil refineries do not have enough to cover their actual emissions while cement plants have more allowances than needed to cover their actual emissions. Then oil refineries can buy some of the surplus allowances (credits) from the cement plants and so help pay for the emission reductions implemented by those plants.

Thus, the way allowances are distributed (or baselines are set) affects how the cost of achieving the emission reductions is distributed among participants. The manner in which allowances are distributed (or baselines are set) can also affect the cost of achieving a specified emission target or change the total emissions. There is no best way to distribute allowances or set baselines. As a result the distribution of allowances (or establishment of baselines) is one of the key issues in the design of an emissions trading program.

Modeling is used to analyze the implications of a range of options for distributing allowances to, or setting baselines for, trading program participants.

4.2 Distribution of Allowances

An emissions trading program must distribute the rights to the allowable emissions. How this is done depends, in part, upon the design of the program.

In a "cap and trade" design, the regulatory authority issues allowances equal to the allowable emissions; for example, if the SOx limit is 495 kt, 495,000 allowances for 1 tonne of SO_x

would be issued. The allowances could be distributed to the trading program participants and/or others and the distribution could be free or the allowances could be sold. Most existing programs distribute the allowances free mainly, or exclusively, to participants.

In a "baseline and credit" design, the regulatory authority approves an emissions baseline for each participant.[24] A participant whose emissions are lower than its baseline receives credits for the difference. A participant whose emissions are higher than its baseline must purchase credits equal to its excess emissions to achieve compliance. The baseline is equivalent to a free distribution of allowances to the participant, so the issues will be discussed in terms of the distribution of allowances even though a baseline and credit design might be implemented.

How allowances are distributed, or baselines are set, affects how the cost of achieving the emission reductions is distributed among participants. Some methods of distributing allowances or defining baselines can also increase the total emissions or the cost of achieving a given emissions target. There is no best way to distribute allowances or set baselines. The main effect of different distributions is on how the costs are spread among participants. Participants will have different views on their fair share of the total cost and hence prefer different methods of distributing the allowances.

But the distribution method can also affect the total cost or total emissions. An allocation or baseline tied to output is equivalent to a production subsidy -- each unit of additional output earns the producer extra allowances or a higher baseline. Compared to an allocation or baseline that does not change with output, the extra allowances are an incentive to increase production. The emissions associated with the higher production increase the cost, relative to a design where the allocation or baseline does not vary with output, of meeting a given emissions target. Alternatively, if an allocation per unit of output is inferred from the output corresponding to an allocation or baseline that does not vary with output and is then used as the allocation rate in an output-based allocation or baseline, the result will be higher output and higher total emissions.

The distribution of costs for, and the other consequences of, different distribution methods can only be estimated through modeling. Recall that MARKAL represents most sectors that would be covered by the emissions trading program as production processes, which do not correspond to specific firms especially in the future. Thus, the cost distribution can be calculated at the industry level, not the entity level.

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[24] The sum of the baselines is the overall emissions limit.

4.3 Distribution Options Modeled

The following options for the distribution of allowances were modeled:

Option 1. **Auction of all allowances**: An auction of all SOx, NOx and GHG allowances. MARKAL is able to calculate the revenue raised from the sale of each type of allowance, but not how the revenue is used. The revenue can be used for many purposes including lower taxes on industry; assistance to workers, communities or firms that are adversely affected; and reduced taxes on individuals to offset price increases; and additional government programs. Since the model does not reflect the use of the revenue, it shows the maximum impact on participants of this distribution option.

Option 2. **Entity grandfathering of allowances**: Each participant receives a free allocation of SOx, NOx and GHG allowances equal to its share of the emissions in 2000.[25] New sources get no allowances; they must buy allowances to cover their total SOx, NOx and GHG emissions. Entities that existed in 2000 and cease operation continue to receive their share of the allowances.[26]

Option 3. **Mixed distribution of allowances**: Each participant receives a free allocation of SOx and NOx allowances as in Option 2 (Entity grandfathering) and a free allocation of GHG allowances based on its output. As in Option 2, a participant's free allocation of SOx and NOx allowances is equal to its share of the emissions in 2000. New sources get no SOx or NOx allowances and entities that existed in 2000 and cease operation continue to receive their share of the SOx or NOx allowances.

GHG allowances are distributed free to each participant based on actual output in the current year multiplied by an allocation rate per unit of output.[27] The allocation rate is calculated as the percentage reduction from 2000 emissions per unit of output needed to achieve the emissions target.[28] This method of allocation provides free GHG allowances to new sources. Participants that cease operation no longer receive allowances. The GHG allocation is equivalent to a baseline and credit design where the baseline for each entity is the allocation rate multiplied by the entity's actual output.

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[25] For example, assume that a participant has SOx emissions of 60 kt in 2000, 12.12% of the 495 kt of SOx emissions in 2000 by program participants. If the SOx target in 2020 is 346.5 kt (a 30% reduction), then this participant would receive allowances equal to 12.12% of the target -- 42,000 SOx allowances.

[26] While these provisions for treatment of new sources and sources that cease operation may seem inequitable, they are used in several SOx and NOx programs including the US Acid Rain, RECLAIM, and NOx Budget programs.

[27] This is the same concept as the provincial target of a 50% reduction of greenhouse gas emissions relative to GDP from the 1990 level in 2020.

[28] Assume that the output of each participant in 2020 is multiplied by the relevant 2000 emissions per unit of output and the resulting emissions are summed, the total is 300 Mt CO_2e. The target in 2020 is 218 $MtCO_2e$ or 72.67% of the total. Then the allocation to a participant would be its actual output in 2020 multiplied by the relevant 2000 emissions per unit of output times 72.67%.

Option 4. **Output-based allocation of allowances**: Each participant receives free SOx, NOx and GHG allowances equal to its actual output in the current year multiplied by an allocation rate per unit of output. The allocation rate is calculated as the percentage reduction from 2000 emissions of SOx/NOx/GHG per unit of output needed to achieve the emissions target for the substance. This is equivalent to the usual definition of a baseline in a baseline and credit design for all three substances.

The allocation options are summarized in Table 6. Option 2 is a fixed distribution of SOx, NOx and GHG allowances based on emissions in the base year (2000). Options 3 and 4 provide respectively no and full adjustment for changes in output in the distribution of SOx and NOx allowances with full adjustment for changes in output in the distribution of GHG allowances. New (existing) sources get more (fewer) GHG allowances under Options 3 and 4 than under Option 2. New (existing) sources get more (fewer) SOx and NOx allowances under Option 4 than Options 2 and 3. Since MARKAL does not distinguish individual entities it is not possible to calculate average allocations for new and existing sources under the different options.

Table 6: Basis for Allocations to Existing and New Entities Under Alternative Allowance Distributions

	Option 1 **Auction**	**Option 2** **Entity Grandfathered GHG, SOx, and NOx**	**Option 3** **Entity Grandfathered SOx and NOx Output-Based GHG**	**Option 4** **Output-Based GHG, SOx and NOx**
GHG Allowances				
Existing sources	0	Base year emissions[a]	Current output	Current output
New sources	0	0	Current output	Current output
SOx Allowances				
Existing sources	0	Base year emissions[a]	Base year emissions[a]	Current output
New sources	0	0	0	Current output
NOx Allowances				
Existing sources	0	Base year emissions[a]	Base year emissions[a]	Current output
New sources	0	0	0	Current output

a The base year can be a single year or period prior to the start of negotiations relating to the allocation of allowances. For modeling purposes the base year is assumed to be 2000.

In the model the allocation rates for output-based allocations or baselines (GHGs in Option 3 and SOx, NOx and GHGs in Option 4) can be set so that the corresponding aggregate emissions target is achieved. In practice, this could only be achieved if the allocation rates are set at the end of the year. That would mean participants could not be sure whether they had achieved compliance until after the end of the year because their allocation rate would not be known. That would inhibit trading and so reduce the cost savings.

The use of output-based allocations or baselines would probably provide for periodic adjustment of the allocation per unit of output.[29] And the allocation to a participant might be based on output during an earlier year, rather than the current year.[30] Then participants would know their allocation or baseline at the beginning of the year and could plan their compliance accordingly. But that would mean the aggregate emissions target may not be met for a given year -- actual emissions could be higher or lower than the target. The environmental integrity of the program then depends upon the provisions for adjusting the allocations if the actual emissions exceed the aggregate target.

An output-based allocation (or a baseline that varies with output) is equivalent to a production subsidy, so production will be higher under such options (3 and 4) than under options (auction and grandfathering) where the allocation (baseline) is fixed. Output-based allocation (or baselines that vary with output) also change the distribution of allowances as output changes -- an entity growing rapidly gets more allowances (a relatively higher baseline) while an entity that is growing slowly gets fewer allowances (a relatively lower baseline).[31]

4.4 Emissions Targets Used to Analyze Options for the Distribution of Allowances

The emissions targets used to analyze options for the distribution of allowances are the Medium SOx, NOx reductions (Case 4 in the previous section):

- The cap on GHG emissions for large industrial sources declines from 178 $MtCO_2e$ in 2010 to 158 $MtCO_2e$ in 2020. Trading program participants are allowed to buy/sell allowances from/to an external market at $10/t CO_2e in 2010 rising to $16 in 2020.[32]

- The SOx target for large industrial sources is a 30% reduction from 2000 emissions in 2020 with the emissions cap taking effect in 2010.

- The NOx target for large industrial sources is equal to 2000 emissions in 2020 with the emissions cap taking effect in 2010.

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[29] The allocation rate per unit of output could be revised on a regular basis, such as every 2 or 5 years and/or if total emissions exceeded the aggregate target by a specified amount, say 10%.

[30] The allocation for a compliance year (e.g. 2005) could be based on actual output during an earlier year for which the output is already known (e.g., 2003) so that the actual allocation or baseline for each participant (its output during 2003 multiplied by the allocation rate, which is fixed for a specified period prior to the start of the year) can be calculated prior to the start of the compliance year.

[31] The allocation could also be based on input. The reasons why output is preferred are discussed in Part 5.

[32] These prices are in year 2000 Canadian dollars.

- Mercury emissions by each electricity generator are reduced by 50% from Base case levels beginning in 2010 (no trading of mercury permits).

Limits are also imposed on the quantity of SOx and NOx allowances that can be banked for use in future periods. The limits are:

- 50 kt for NOx emissions. This is about 10% of the average target for 2010, 2015 and 2020. This limit is similar to that of the Ozone Transport Commission NOx Budget program whose "flow control" provision discounts allowances once the bank exceeds 10% of allowable emissions. This limit also allows virtually all of the necessary reduction to be made one period earlier; i.e., with a bank of 50 kt in 2010 no additional reductions are needed in 2015.

- 75 kt for SOx emissions. This is about 18% of the average target for 2010, 2015 and 2020 and is roughly sufficient to allow virtually all of the necessary reduction to be made one period earlier. No existing program that allows banking of SOx allowances limits the quantity that can be banked.

4.5 Modeling Results

4.5.1 Total Cost and Allowance Prices

The costs, emissions reductions, and allowance prices under different allowance distribution options are summarized in Table 7. Mercury is not included in Table 7 because it is not part of the trading program, but the coal-fired electricity generating units are still subject to the mercury emissions constraint for Case 4.

A comparison with Table 3 indicates that banking reduces the total cost of achieving the aggregate targets -- under Option 2 the total cost is $98 million compared with $110 million for Case 4 in Table 3 with no banking. Banking leads to larger SOx and NOx emission reductions in 2010 and/or 2015 and lower reductions in 2020. Since the GHG intensity declines over time, SOx and NOx banking leads to a slightly larger reduction of GHG emissions (about 520 $MtCO_2e$ compared with 505 $MtCO_2e$ with no banking).

Table 7 indicates that an output-based allocation (or baseline that varies with output) for GHGs increases the total cost significantly. The total cost for Options 3 and 4, which feature output-based allocation of GHG allowances, is almost four times the total cost of Option 2, where the allocation of GHG allowances is fixed, to meet the same aggregate GHG target. In contrast, an output-based allocation (or baseline that varies with output) for SOx and NOx allowances has virtually no impact on the total cost. The cost of Option 3, where the SOx and NOx allocations are fixed, is almost identical to the cost of Option 4 which uses an output-based allocation for SOx and NOx allowances.

Table 7: Cost of Meeting the Specified Emissions Targets with Different Distribution Options

	Total Cost[a]	Cumulative Emission Reductions[b]			Price of Allowances[c]		
	(millions of 1995$)	GHGs[d] (MtCO$_2$e)	SOx (kt SO$_x$)	NOx (kt NO$_x$)	GHGs[c] ($/tCO$_2$e)	SOx[c] ($/t SO$_x$)	NOx[c] ($/t NO$_x$)
Option 1 **Auction**		424 96 520	1,962	2,071	$9 $12 $15	$136 $218 $218	$61 $61 $98
Option 2 **Entity Grand-fathering for SOx, NOx and GHGs**	$98	424 96 520	1,962	2,071	$9 $12 $15	$136 $218 $218	$61 $61 $98
Option 3 **Entity SOx and NOx Grandfathering, Output-based GHG Allocation**	$366	215 304 519	1,962	2,071	$9 $12 $15	$136 $218 $352	$61 $98 $158
Option 4 **Output-Based Allocation for SOx, NOx and GHGs**	$370	213 306 519	1,962	2,071	$9 $12 $15	$136 $218 $352	$61 $98 $158

Notes:

a The total cost is the net present value in 2000 of costs incurred over the period 2000 through 2020 discounted at 10% per year. All figures are in 1995 Canadian dollars.

b Cumulative emission reduction is calculated as the sum of the reductions from Base case emissions for 2010, 2015 and 2020 multiplied by 5.

c Allowance prices are for 2010, 2015 and 2020 respectively in 1995 Canadian dollars. The GHG allowance prices of $9 in 2010 and $15 in 2020 are equivalent to the prices of $10/tCO$_2$e rising to $16/tCO$_2$e in 2000 Canadian dollars assumed for the external market. In all of these options Alberta is a net importer of GHG allowances and the Alberta price is set by the external market.

d The figures are respectively (i) the GHG emission reductions by participants in the trading program, (ii) the credit purchases from sources outside the trading program, and (iii) the total reduction achieved by the participants in the trading program.

4.5.2 Output Growth and Emissions Reductions by Industry Sector

A free allocation, or baseline that varies with output, is equivalent to a production subsidy, so total output is higher than under a grandfathered allocation or auction. The options are modeled so that the emissions associated with the higher output must be accommodated within the fixed target.[33] In the case of GHGs, the extra emissions are covered by larger purchases of credits from outside the trading program. The GHG credit purchases are over three times higher under Options 3 and 4 (output-based allocation) than under Option 2 (grandfathered allocation). For SOx and NOx external credit purchases are not allowed in the model, so the emissions associated with the higher output lead to higher SOx and NOx allowance prices in Options 3 and 4 relative to Option 2.

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[33] The output-based options could also be modeled by assuming that the allowable emissions per unit of output is the same as for Option 2 where the allocation is fixed. Then the higher output under Options 3 and 4 would lead to higher total emissions than under Option 2. There would still be impacts on profits under Options 3 and 4. So a comparison of Options 3 and 4 with Option 2 would involve both emissions and costs. Modeling Options 3 and 4 to meet the same emissions target as Option 2 means that all of the impacts are in monetary units. This makes it easier to compare the options.

To meet the SOx and NOx targets despite the higher output under Options 3 and 4, some industry sectors must implement larger emission reductions. The electricity generation, natural gas production and oil refinery industries implement larger SOx reductions and electricity and natural gas industries implement bigger NOx reductions than under an auction or grandfathered allocation (Options 1 and 2). The SOx and NOx emission reductions for a grandfathered allocation or auction are the same as those for Case 4 in Table 4.

The impact of different allowance distribution options on industry output yields no surprises. Table 5 indicated that the output of the energy producing industries -- conventional oil, natural gas, and oil sands -- remained constant when the emissions constraints were modeled. Thus it is not surprising that their output remains the same for all of the distribution options.

Under Option 2 (and Option 1) the output reductions from the Base case are identical to those shown in Table 5 for cement, chemicals, electricity generation, oil refining and pulp and paper. This is because the allowance distribution does not vary with output. With a free allocation or baseline that varies with output (Options 3 and 4) the output impacts are smaller, but output growth is still lower than in the Base case for each of these industry sectors. The impacts on the output of these sectors are shown in Table 8.

The mining and other manufacturing sectors are not part of the emissions trading program in the model, but their output is affected by the introduction of emissions targets. The impact on the output of the mining and other manufacturing sectors is the same as shown in Table 5 for all of the allocation options.

Table 8: Changes in Industry Output by Allocation Option

Industry Sector[a]		Output Growth Rate (percent per year)				
		2000-2005	2005-2010	2010-2015	2015-2020	2000-2020
Cement	Base case	2.16%	1.29%	-0.29%	1.30%	1.11%
	Option 2	-2.61%	-3.00%	-3.53%	0%	-2.30%
	Option 3	2.16%	-0.83%	-1.72%	0%	-0.11%
	Option 4	2.16%	-0.83%	-1.38%	0.04%	-0.11%
Chemicals	Base case	3.00%	2.72%	3.38%	2.76%	2.96%
	Option 2	3.00%	-2.24%	0.39%	2.23%	0.83%
	Options 3, 4	3.00%	2.72%	2.23%	2.07%	2.50%
Electricity Generation	Base case	2.94%	1.35%	1.51%	0.79%	1.65%
	Option 2	2.77%	0.37%	1.02%	0.79%	1.23%
	Option 3	2.97%	1.05%	1.48%	1.04%	1.63%
	Option 4	3.00%	1.05%	1.48%	1.04%	1.64%
Oil Refining	Base case	-1.35%	0.35%	4.31%	0.62%	0.96%
	Option 2	-1.50%	0.06%	4.34%	0.61%	0.85%
	Options 3, 4	-1.50%	0.10%	4.35%	0.65%	0.88%
Pulp and Paper	Base case	1.25%	1.24%	1.12%	1.15%	1.19%
	Option 2	1.25%	-0.87%	-1.23%	1.15%	0.07%
	Options 3, 4	1.25%	1.24%	-0.99%	1.16%	0.66%

a The output of the natural gas, conventional oil and oil sands sectors does not change with the allocation option. The output growth rates for these sectors are the identical to those for the Base case shown in Table 5 for all allocation options.

4.5.3 Impacts on Profits by Industry Sector

The impacts of different allocation options on profits by industry sector are shown in Figure 4. The figure shows the increase or decrease in profits relative to the Base case as a percentage of industry revenue. Profits increase for some industries (oil refineries, pulp and paper) under all of the allocation options modeled. Most industry sectors show profit increases for some allocation options and profit declines for other allocation options. Only the oil sands sector is expected to experience lower profits under all of the allocation options.

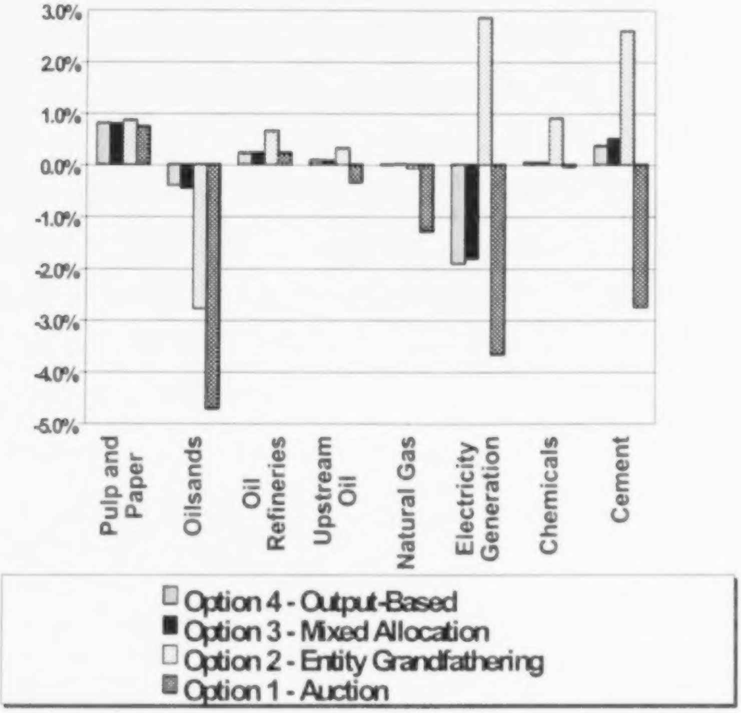

Figure 4: Impacts on Profits

Changes in Profits as a Percent of Base Case Sales

An auction (Option 1) usually results in the largest reduction (or smallest increase) in profits for an industry sector. However, MARKAL is not able to analyze how the auction revenue is used. If some or all of the revenue is used to reduce taxes on industry, the adverse profit impacts would be smaller. The impact on profits by sector would depend on which taxes are reduced.

Entity grandfathering (Option 2) yields the largest profit increase for all sectors except oil sands and natural gas. In the case of oil sands this is due to the rapid growth of the sector -- output-based allocations assign more of the allowances to this sector and so have a smaller adverse impact on its profits. The natural gas sector is the source of most of the extra SOx and NOx reductions needed under an output-based allocation, so it sells more allowances at higher prices under such allocations and so is more profitable under those allocation options than under entity grandfathering.

The profit impacts of Options 3 and 4 are similar. These options involve a GHG baseline that varies with output (an output-based allocation of GHG allowances), but entity grandfathering (Option 3) or output-based (Option 4) allocation of SOx and NOx allowances. Due to its rapid growth relative to other industry sectors, the output-based allocation (or baseline) for SOx and NOx (Option 4) results in a smaller profit reduction for the oil sands sector than a fixed allocation (or baseline) for SOx and NOx based on emissions in 2000 (Option 3). Almost every other sector is better off under Option 3 than under Option 4, with the biggest differences occurring in the cement and electricity generation sectors.

4.5.4 A "Fair" Allocation of GHG Allowances

Figure 4 indicates that none of the allocation options modeled is likely to be considered "fair" by all industry sectors. Profits rise for some industries and fall for others under any of the options.

Allocation principles that might be considered "fair" by all industries include:

- an equal change in the Base case profits as a percentage of sales across all sectors;[34] and
- an equal reduction in profits per tonne of Base case emissions.[35]

The calculations focus on profits to capture the net effect of impacts on prices, output and compliance costs, rather than compliance costs alone. These "fair" allocations cannot be implemented in practice since they require information on the change in profits and the Base case emissions, which cannot be determined in practice. Thus, these allocations serve simply as standards against which the options analyzed (or other allocations) can be compared.

Table 9 shows the GHG allowance allocations by industry sector under Options 2, 3 and 4 together with those for the two "fair" allocations defined above. The calculations to determine the "fair" allocations ignore the distribution of SOx and NOx allowances since the allocation options for those allowances have a very small impact on the total cost and the change in profits.

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[34] Profits as a percent of revenue differ across sectors in the Base case, say 5% for cement and 8% for oil refineries. (These are hypothetical values because MARKAL calculates the *change* in profits not the *actual* profits by sector.) In the case of Option 4, the overall impact is a profit is a decrease of $398 million or -0.05% of Base case revenue. This allocation, then, is one that yields profits of 4.95% and 7.95% of Base case revenue for the cement and oil refinery industries.

[35] Base case GHG emissions for the trading program participants average 198.2 $MtCO_2e$ for the period 2020-2020. The decrease in profit is $398 million, or $1.95/$tCO_2e$ of Base case emissions. This allocation, then, is one that yields a profit decline of $2.01/$tCO_2e$ multiplied by the Base case emissions of each industry sector.

Table 9: Comparison of Sectoral GHG Allocations Under Different Options
(Million tonnes CO_2e/year)

	Options 3 and 4				Average Annual Allocation 2010 to 2020		
	2010	2015	2020	Average	Option 2	Equal Percent Loss of Profit	Equal Profit/ Loss per tonne
Cement	2.0	1.8	1.5	1.8	2.6	1.4	5.1
Chemicals	13.3	14.3	13.8	13.8	14.1	2.5	25.1
Electricity Generation	49.2	49.1	43.7	47.3	56.4	33.0	-40.7[a]
Natural Gas Production	37.7	36.1	31.3	35.0	44.4	56.7	0.6
Oil Production (Conventional)	9.5	8.8	6.9	8.4	14.7	7.4	28.0
Oil Refining	5.2	6.2	5.6	5.7	7.9	-1.2[a]	51.4
Oilsands	53.9	56.1	48.9	53.0	24.7	65.1	40.8
Pulp and Paper	0.6	0.5	0.5	0.5	0.7	0.6	55.2
Total	171.3	172.9	152.2	165.5	165.5	165.5	165.5

Note: [a] A negative allocation means that the profit impacts due to price and output changes are smaller than needed to satisfy the allocation principle, so to meet the principle the industry would need to buy allowances in excess of its actual emissions.

The allocations under Options 2 and 3 - 4 differ in the predicted manner. Since Options 3 - 4 adjust for changes in output and Option 2 does not, the allocation to the rapidly growing sector -- oil sands -- is higher under Options 3 - 4 than under Option 2. Conversely, the allocations to all other industries are lower under Options 3 - 4 than under Option 2.

The two "fair" allocation principles yield very different allocations. Each one has a negative allocation for one sector. A negative allocation means that the profit impacts due to price and output changes are smaller than needed to satisfy the allocation principle, so to meet the principle the industry would need to buy allowances in excess of its actual emissions. The allocations under Options 2 and 3 - 4 are closer to the allocation corresponding to the principle of equal reduction in the Base case profits as a percentage of sales.

The large differences between the two "fair" allocation principles and the relatively large differential impacts in profit impacts across sectors for the allocation options modeled suggest that no single allocation option will be acceptable for all industries. Rather a combination of allocation options or a single option with adjustments for some sectors probably will be needed.

4.5.5 The Allowance Market Under Different Allocations

With a baseline and credit design or free distribution of allowances, the baselines or allocation formula influences which participants will be buyers and which will be sellers. Thus the baselines, or allocation formula, influence whether the market for allowances is competitive.

All of the allocation options modeled assume that participants in the Alberta GHG trading program will be able to buy allowances or credits from sources outside the program, including sources outside the province. As shown in Table 7, participants in the trading program are projected to purchase external allowances/credits equivalent to a substantial share of their emission reduction target. Purchases represent about 18% of the reduction target under Option 2 and close to 60% of the reduction target under Options 3 and 4. Under Options 3 and 4 all industry sectors buy external GHG allowances/credits; thus, a competitive market requires that Alberta participants have access to a large number of sellers outside the trading program.

As will be discussed in Part 5, use of SOx and NOx allowances/credits from other jurisdictions is not recommended. In addition, the scope for SOx and NOx credits from Alberta sources outside the trading program is limited. Thus the SOx and NOx markets have been modeled as being limited to the participants. The buyers and sellers in the SOx and NOx markets under different allocation options are shown in Table 10.

Option 2 allocates SOx and NOx allowances on the basis of emissions in 2000. The oil sands sector is the dominant net buyer of SOx allowances and the only net buyer of NOx allowances. The principal sellers of SOx and NOx allowances are the conventional gas and oil sectors. The electricity generators are also net sellers of NOx allowances. Since new sources receive no allowances under this option, there would be buyers and sellers within some sectors as well. This suggests at least 20 relatively large buyers and a larger number of sellers for both SOx and NOx allowances.

Option 3 also allocates SOx and NOx allowances on the basis of emissions in 2000, but GHG allowance allocations or baselines are based on output. The GHG allocation affects output and hence SOx and NOx emissions and SOx and NOx trading. However, the basic pattern is the same as for Option 2. The oil sands sector is the dominant net buyer of SOx allowances and the only net buyer of NOx allowances. The principal sellers of SOx and NOx allowances are the conventional gas and oil sectors. The electricity generators are also net sellers of NOx allowances. As in the case of Option 2, this suggests at least 20 relatively large buyers and a larger number of sellers for both SOx and NOx allowances.

Table 10: Buyers and Sellers in the SOx and NOx Markets Under Different Allocation Options

(kilotonnes per year)

		SOx				NOx			
		2010	2015	2020		2010	2015	2020	
Sector/Number Entities		Option 2: Entity Grandfathering for SOx, NOx and GHGs							
Cement	2	-0.6	-0.9	-0.5	sell	-2.2	-2.4	-1.8	sell
Chemicals	20					-4.6	-3.1	0.0	sell
Electric Power	55	-6.6	5.0	14.4	bank, buy	-35.8	-29.0	-23.0	sell
Gas Production	100+	-75.5	-69.3	-107.3	sell	-22.0	-77.5	-45.7	sell
Oil Production	100+	-12.7	-9.8	-6.4	sell	-24.1	-23.0	-22.4	sell
Oil Refineries	4	-0.5	-1.4	0.9	bank, sell	-1.4	0.1	0.8	bank, sell
Oilsands	24	78.5	93.3	98.2	buy	91.1	109.2	116.3	buy
Pulp and Paper	4	0.1	0.2	0.6	buy	-0.8	-0.7	0.1	bank, sell
Total		**-17.2**	**17.2**	**0.0**	bank	**0.0**	**-25.9**	**25.9**	bank
		Option 3: Entity Grandfathering for SOx and NOx and Output-based GHG Allocation							
Cement	2	0.3	0.0	0.4	buy	-0.7	-0.7	-0.1	sell
Chemicals	20					-0.9	1.8	5.6	bank, buy
Electric Power	55	3.0	17.5	37.3	buy	-26.8	-18.8	-10.7	sell
Gas Production	100+	-75.5	-108.3	-113.8	sell	-57.3	-87.0	-45.7	sell
Oil Production	100+	-12.7	-9.8	-6.4	sell	-26.8	-25.7	-24.2	sell
Oil Refineries	4	-0.4	-1.3	-1.8	sell	-1.4	0.1	0.9	bank, sell
Oilsands	24	78.5	93.3	14.7	buy	91.1	109.2	116.3	buy
Pulp and Paper	4	0.3	0.5	0.9	buy	-0.3	-0.2	0.5	bank
Total		**-6.5**	**-8.3**	**14.7**	bank	**-23.5**	**-20.8**	**44.3**	bank
		Option 4: Output-based Allocation for SOx, NOx and GHGs							
Cement	2	1.1	0.9	1.2	buy	0.6	0.9	1.4	buy
Chemicals	20					-0.4	0.9	3.1	bank, buy
Electric Power	55	27.5	41.1	56.8	buy	-15.2	-9.1	-3.8	sell
Gas Production	100+	-27.7	-60.4	-74.4	sell	-18.6	-43.8	-7.4	sell
Oil Production	100+	0.0	2.5	4.7	buy	0.4	2.3	4.2	buy
Oil Refineries	4	4.5	1.7	0.4	buy	0.5	1.1	1.6	buy
Oilsands	24	-12.7	4.7	24.7	bank, buy	9.5	25.8	41.8	buy
Pulp and Paper	4	0.9	1.0	1.3	buy	0.5	0.8	1.2	buy
Total		**-6.5**	**-8.5**	**14.7**	bank	**-23.1**	**-20.4**	**43.7**	bank

Option 4 allocates SOx and NOx allowances (sets SOx and NOx baselines) on the basis of output. The conventional gas sector is the only net seller of SOx allowances and the main seller of NOx allowances. The electricity generators are also net sellers of NOx allowances. All other sectors are net buyers of both SOx and NOx allowances. Under this option, new sources are allocated SOx and NOx allowances based on their output, so they are not as dependent on the market for their allowances. The large number of sources in the conventional gas sector suggests that they probably will not be able to exercise market power.

The assumed limits on banking are not binding. NOx banking amounts to 44 kt for Options 3 and 4 compared with a limit of 50 kt. SOx banking is less than 20 kt under all options, compared with the limit of 75 kt.

Not surprisingly, the SOx and NOx allocation options affect which participants are buyers and sellers. The GHG allocation also affects which participants are buyers and sellers of SOx and NOx allowances. For the options modeled, there are likely to be at least 20 relatively large buyers and sellers in both the SOx and NOx markets. This should be sufficient to create a competitive market. However, if all allowances are distributed free, the possibility of withholding some of the allowances for auction to ensure a competitive market should be considered. The auction proceeds would be distributed to the participants in lieu of free allowances.[36]

4.6 Sensitivity to Natural Gas Price

The sensitivity of the results for Option 4 to the projected price of natural gas was analyzed. The price of natural gas delivered to industry in Alberta was assumed to be equal to $5/GJ (expressed in 2000 C$) for the full 2000 - 2020 period in the sensitivity case. In the Base case and Option 4 the industrial price of natural gas is close to $4.00/GJ.[37] The price of exported gas is the Alberta price plus transportation charges in each case. Full results are provided in Appendix A.

The main effect of the higher gas price is a significant delay in the development of some of the oil sands projects. This happens because oil sands production uses a lot of natural gas and the higher gas price reduces the profitability of proposed projects. The result is much lower oil sands production relative to the Base case and Option 4 in 2005 (-27%), 2010 (-16%) and 2015 (-42%), but not in 2020 when oil sands output is the same as in the Base case.

Lower oil sands production means lower emissions and smaller allocations (lower baselines) for this sector. This means lower GHG allowance/credit purchases from outside the trading program prior to 2020 and more banking of SOx and NOx allowances in 2010 and 2015 for use in 2020 when oil sands production reaches the level projected for the Base case. This in turn lowers the prices of SOx and NOx allowances from the levels under Option 4 throughout the 2010 - 2020 period.

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[36] For example if 10% of the SOx (NOx) allowances were withheld for auction, a source would receive an allocation of 90% of the SOx allowances it was entitled to and cash equal to the average auction price for the remaining 10% of the allowances.

[37] It was also necessary to rerun the Base case with the higher gas price to assess some of the impacts.

Another major consequence of the reduced oil sands emissions in 2010 and 2015 is that smaller emission reductions are needed in most sectors to meet the emissions targets for the trading program. And the smaller allocations to the oil sands sector mean larger allocations to all other sectors. The result is that output of all sectors other than oil sands is the same as in the Base case. Within the electricity generation sector the higher gas price means less gas-fired and more coal-fired generation than in Option 4.

4.7 Conclusions

How allowances are distributed determines how the costs are distributed and can affect the total cost. The distribution options analyzed are deliberately defined to be significantly different and span the full range of possibilities. In practice intermediate cases, such as special treatment of new sources or a transition from free distribution to an auction, are possible. Banking, as expected, reduces the cost of meeting the aggregate emissions targets.

The total cost is particularly sensitive to the method used to distribute GHG allowances. The costs are roughly four times higher when allowances are distributed, or the baseline is set, on the basis of output than if the allocation is fixed (grandfathering). Given an output-based allocation for GHG allowances, the method of distributing SOx and NOx allowances has little impact on the total cost.

The rapid growth projected for the oil sands sector affects all participants. If the baseline or allocation is proportional to base year emissions (grandfathering), new oil sands projects must buy large quantities of allowances from the other industries, which results in a reduction of the projected profits of the oil sands sector. On the other hand, an output-based allocation leads to a shift in the allocation of allowances from all other industries to the oil sands sector. The same happens in a baseline and credit design if the baselines are adjusted to meet the aggregate targets. The larger allocation (baselines) for the oil sands sector impose higher costs on all other industries. In short, the choice of a distribution option depends to a significant extent on what is considered a fair distribution of the economic burden of the growing emissions of the oil sands sector.[38]

The main purpose of the allowance distribution or establishment of baselines is to distribute the costs of meeting the emissions targets "fairly". The relevant costs include not only the costs of implementing emission reduction measures, but also the net cost of allowance/credit purchases and sales, and impacts on profits due to changes in output and/or prices.

The output of the energy producing industries -- conventional oil, natural gas, and oil sands -- is not affected by the distribution options analyzed. The output of the cement, chemicals, electricity generation, oil refining and pulp and paper industries is reduced by imposition of the emissions target. The output declines are smaller with a free allocation, or baselines, that vary with output, than under a fixed allocation or baseline not tied to output. But even with an output-based allocation or baseline, the output growth in each of these industry sectors is lower than in the Base case.

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[38] The gas price sensitivity case illustrates this clearly. The higher natural gas prices delay the expansion of the oil sands output. As a result of the delayed oil sands expansion, there are no adverse output or profit impacts on any other sector except gas-fired electricity generation.

For all of the distribution options modeled, except an auction, profits are higher than in the Base case for cement, chemicals, conventional oil, oil refineries, and pulp and paper. Profits are lower than in the Base case for the natural gas (by negligible amounts) and oil sands sectors. The profits of electricity generators increase or decrease depending upon the distribution option. The model is not able to analyze how the auction revenue is used. If some or all of the revenue is used to reduce taxes on industry, the adverse profit impacts would be smaller. The impact on profits by sector would depend on which taxes are reduced.

Profits are highest for all sectors, except oil sands and natural gas, with a fixed allocation or baseline not tied to output. With an output-based allocation, or baselines tied to output, profits are lower than with a fixed allocation or baseline not tied to output, but still higher than in the Base case for all sectors except electricity generation, oil sands and natural gas (by a negligible amount).

Thus, for all sectors except oil sands and natural gas the choice is between:

- a fixed allocation, or baseline not tied to output, whose consequences are higher profits but lower output than in the Base case; and
- an output-based allocation, or baseline tied to output, whose consequences are higher output and lower profits than with a fixed allocation, but still below the output and above the profits in the Base case.

The output of the natural gas and oil sands sectors is constant for all of the options modeled, so only the profits change.

The profit impacts described above are most pronounced for the distribution of GHG allowances, but also apply, on a much smaller scale, to the distribution of SOx and NOx allowances.

The treatment of new sources is not modeled because individual entities are not represented in the model. The major SOx and NOx trading programs in the United States do not provide allowances to new sources. If allowances are distributed in proportion to emissions during a base year, some allowances can be withheld for new sources although this requires a formula for determining how many to allocate to a new source. If allowances are distributed in proportion to current output, the same allocation rule or baseline can be applied to new and existing sources.

The relatively large differences in profit impacts across sectors for the allocation options modeled suggest that no single allocation option will be acceptable for all industries. This implies that a combination of allocation options or a single option with adjustments for some sectors and/or entities probably will be needed. As noted above, the preferred distribution option depends to a significant extent on what is considered a fair distribution of the economic burden of the growing emissions of the oil sands sector.

Profits are higher for several sectors with an emissions constraint and free distribution of allowances or a baseline and credit design than in the Base case. The profit figures presented are the present value of the profit changes over the period analyzed (2000 - 2020). Profits are often lower when the emissions trading program begins and rise after the emission reduction actions have been implemented.

The model results suggest that there will be enough buyers and sellers to create competitive markets for the allowances of each of the substances. Participants are projected to purchase relatively large quantities of GHG allowances/credits from external sources. Thus, a competitive GHG allowance market in Alberta requires that Alberta participants have access to a large number of sellers outside the trading program. The participants that are SOx and NOx buyers are partly determined by the GHG target and the distribution of GHG allowances.

While the number of SOx and NOx buyers and sellers appears to be sufficient to create a competitive market, provisions to ensure this is the case should be considered. Banking helps create a more competitive market. An auction also helps make the market more competitive. If all allowances are distributed free, the possibility of withholding some of the allowances for auction with the proceeds distributed to the participants in lieu of free allowances should be considered.

4.8 Recommendation

The following approach is recommended for negotiating the distribution of allowances or establishment of baselines for participants in the emissions trading program.

- Emissions targets are defined for SOx, NOx and GHG emissions by large sources in all sectors excluding oil sands. Each of the industry sectors covered by those targets is allocated a share of the target based on its share of emissions in 2000 (or some other year or period to be agreed). These sector shares are adjusted every five years, or when the emissions caps change, based on the most recent years' actual emissions.

- The participants in each industry sector are offered the choice of a fixed allocation based on an agreed base period or an output-based allocation or baseline.[39] The choice would be binding on all participants in the sector. Industries choosing a fixed allocation would need to agree on a base period and reasonable allocations for new sources. Industry sectors choosing an output-based allocation or baseline must agree on a common measure of output and how it will be monitored. The allocations to individual participants would then be computed from and be constrained to the allocation to the sector.

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[39] The greenhouse gas emissions trading program in the United Kingdom includes a "gateway" that prevents net purchases by participants with absolute allocations from participants with output-based allocations. The main reason for this is that the government offered financial incentives to participants with absolute allocations and wanted to prevent the possibility that emissions by those participants would be higher than the agreed allocation due to purchases from participants with output-based allocations. The recommended structure does not include any restrictions on trading between participants with fixed allocations and those with output-based allocations or baselines.

- SOx, NOx and GHG allocations or baselines for oil sands projects are established separately. Those allocations or baselines should represent a reasonable contribution to reducing provincial emissions. The SOx, NOx and GHG targets would rise by the amount of the allocation or baseline as new projects commenced operation.

If baselines, rather than allowance allocations, are adopted, allowances equal to the baselines, rather than credits equal to reductions from the baseline, should be distributed to improve liquidity, especially in the SOx and NOx markets. Initially, allowances should be distributed free to participants, but with a transition to an auction once costs of emission reduction actions have been recovered and competitors elsewhere face similar emissions regulations.[40]

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[40] Some people argue that free distribution of allowances is a gift of a public good to private interests. Other people argue that since sources currently are allowed to emit SOx, NOx and GHGs free subject to their operating permits an auction of allowances could be interpreted as expropriation of their existing legal rights. Assessment of the merits of these arguments is beyond the scope of this document.

5. Emissions Trading Program Design Issues

5.1 Introduction

Part 2 concluded that emissions trading is feasible in Alberta for SOx, NOx and GHG emissions by large industrial sources. Part 3 concluded that emissions trading could reduce the cost of lowering SOx, NOx and GHGs emissions by large industrial sources because the marginal costs of reducing emissions of these substances differed across industry sectors. Part 4 explored different options for the distribution of allowances, and hence costs, among large industrial sources. This part discusses a number of the design issues raised by an emissions trading program.

The following criteria were used in assessing the options for the design issues:

- Environmental Integrity: effectiveness in achieving environmental air quality objectives.
- Economic Efficiency and Impacts: greatest economic efficiency and least operating cost to participants and government consistent with ensuring the integrity and effectiveness of the trading system and the achievement of environmental management objectives.
- Implementation Costs: lowest implementation costs consistent with ensuring the integrity and effectiveness of the trading system and the achievement of environmental management objectives.
- Stakeholder Acceptability: highest potential acceptability of the option by industry, ENGOs and other stakeholder groups in Alberta consistent with ensuring the integrity and effectiveness of the trading system and the achievement of environmental management objectives.
- Simplicity and transparency: design options that are as straightforward and transparent as possible consistent with ensuring the integrity and effectiveness of the trading system and the achievement of environmental management objectives.
- Consistent with the Alberta Action Plan: design of the greenhouse gas component of the system must be compatible with meeting Alberta's overall intensity target for the province, as well as the development of sectoral emissions intensity agreements.

5.2 Coverage

An emissions trading program should cover as large a share of the total emissions as possible. That enhances environmental integrity by increasing the number of sources whose emissions are regulated. And it improves economic efficiency by increasing the range of emission reduction actions. However, the cost of monitoring equipment makes participation costly for small sources. Small sources also add to the enforcement workload of the regulatory authority while yielding only small environmental benefits.

Emissions trading programs, therefore, typically focus on large sources and require participation by entities that meet specified size criteria. The size threshold is usually defined by annual emissions or a measure of capacity. The Regional Clean Air Incentives Market (RECLAIM) program requires any entity that has a process or piece of equipment that emits 4 tons of SOx or NOx per year to participate. Phase II of the US Acid Rain program applies to all electric utility generating units with an output capacity of 25 MW or greater that use fossil fuels with a sulphur content greater than 0.05%. The OTC NOx Budget program also includes industrial boilers with a rating of 250 million BTU/hr or more. The draft Emissions Trading Directive of the European Commission specifies capacity thresholds for the sectors that would be covered by that GHG trading program.

It is recommended that an Alberta emissions trading program for SOx, NOx and GHGs use a combination of emission thresholds and design capacities to identify participants.[41] An entity that emits more than any of the emissions thresholds or whose capacity exceeds any of the specified thresholds should be required to participate in the program for all of the substances. For example, if the emissions thresholds are 1,000 tonnes per year of SOx or NOx and 10,000 tonnes per year of CO_2e and the capacity threshold for fossil-fired electricity generators is 15 MW, a unit that exceeds any one of these thresholds should be required to participate.[42]

There are three reasons for recommending that an entity that exceeds one of the emission thresholds be required to participate in the trading program for all three substances:

- Participation for any of the substances will require the entity to install monitoring equipment that can monitor emissions of all of the substances at no or little additional cost so the share of total emissions covered by the trading program can be increased with little or no increase in monitoring costs;
- Actions to reduce emissions of one substance could increase emissions of the others. Participation for all substances ensures that the impacts on emissions of all substances are considered when selecting emission reduction measures; and
- The compliance enforcement workload of the regulatory authority is virtually the same whether an entity is a participant for one or three substances.

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[41] The design capacity thresholds will differ across industries, e.g., MW of output for electricity generators and kiln capacity for cement plants.

[42] These thresholds are examples, not recommended thresholds.

Requiring an entity to participate if it exceeds the capacity threshold even if it does not exceed any of the emissions thresholds addresses competitiveness concerns by creating a consistent environmental regulatory regime. It also increases the share of total emissions covered and the range of emission reduction opportunities.

The trading program should include all sources that are large emitters of any of the three substances -- upstream oil and gas, oil sands operations, all types of industrial plants, pipeline compressor stations, etc. The broader the coverage, the greater the environmental integrity and economic efficiency. While their participation is desirable for environmental and economic efficiency reasons, the participation of facilities regulated solely by federal agencies raises legal issues beyond the scope of this document. An appropriate design capacity will be needed for each type of facility. Issues related to sector definitions are discussed further below.

5.3 Participants

It is recommended that the participants with compliance obligations be individual facilities -- a facility located on a single contiguous site or operated independently. Thus, each electricity generating unit, natural gas plant, oil refinery, cement kiln, etc would be a separate participant for compliance purposes. Where two or more facilities have the same owner, the owner can choose where to implement emission reduction actions and transfer allowances/credits internally to achieve compliance. Thus, defining the participants as individual facilities does not constrain the compliance strategy of a firm that owns multiple facilities.

The main advantage of having individual facilities as participants is in the formulation of rules for the free distribution of allowances. Distributing allowances to individual facilities greatly reduces the need for rules to deal with changes in structure such as mergers, divestitures, asset sales, etc. And if baselines are set, or allowances are distributed, on the basis of output, a facility is more likely to have a homogeneous output than a firm, so having individual facilities as the participants simplifies the administration.

Any person or entity should be allowed to trade. Individuals, firms and other organizations that do not have compliance obligations should be allowed to buy and sell allowances and credits. Owners should be allowed to have allowances or credits cancelled. Thus an environmental group could buy and cancel allowances or credits to benefit the environment.

5.4 Emissions Sources Covered

A facility may have numerous sources of SOx, NOx and GHG emissions. The trading program should seek to cover as many of the sources as possible within any facility that meets the threshold for participation. This increases environmental integrity and improves economic efficiency. But it must be possible to measure or calculate the emissions of each source with reasonable accuracy at reasonable cost. Thus small or difficult to measure sources, such as the emissions of standby diesel generators or fugitive methane emissions, might be excluded from the emissions the participant is required to report.

Vehicle fleets are usually excluded from an emissions trading program because the fleet associated with a specific facility is difficult to define and the SOx and NOx emissions are difficult to calculate accurately.[43] However, in certain cases, such as oil sands operations, where the vehicles are an integral part of the production process and the emissions are significant, an effort should be made to include them.

Decisions on which emissions sources should be included will need to be made on a sectoral, and perhaps an individual participant, basis as the feasibility and cost of measuring (or calculating) the emissions is assessed during the detailed design phase.

5.5 Measurement of Emissions

The environmental integrity of an emissions trading program depends upon accurate measurement of the actual emissions by the covered sources at participating facilities. Thus most emissions trading programs set stringent monitoring requirements -- requirements to install the most accurate type of monitoring equipment, regular tests to ensure that the equipment is accurate, and provisions to replace missing or erroneous readings with upwardly biased estimates.

For electricity generators and large industrial boilers covered by American SOx and NOx programs, the requirement is usually to install continuous emission monitors. Continuous emission monitors are expensive, so small sources are allowed to use lower cost emissions monitoring procedures. But the philosophy is that relatively high monitoring costs are acceptable given the compliance cost savings made possible by emissions trading.

Some participants in the RECLAIM program encountered difficulties getting their monitoring equipment installed and functioning properly and were required to calculate their emissions using the missing data protocol.[44] These problems were overcome, but the experience suggests that it may be desirable to mandate emissions monitoring for a year or two prior to the start of the trading program.

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[43] To include vehicle emissions in the trading program it is necessary to specify which emissions a participant is responsible for. A large industrial source could be held responsible for the emissions by vehicles it owns or leases. A trading program would not include all trucking firms since some would have emissions lower than the threshold for participation and others are not based in Alberta. Then a participant could reduce its vehicle emissions by getting rid of its fleet and contracting with trucking firms for the delivery of its products. The manin effect is to reward participants for shifting emissions from sources covered by the trading program to sources outside the trading program. The GHG emissions of vehicles can be calculated accurately from the fuel use.

[44] See the U.S. Environmental Protection Agency evaluation of RECLAIM.

5.6 Verification and Enforcement

The regulatory authority must verify the performance of the monitoring equipment, reported emissions (including adjustments for missing data) and the validity of the allowances or credits used for compliance at the end of each compliance period. Some of this work, testing monitoring equipment for example, can be delegated to accredited independent experts.

Ultimately, however, it is the responsibility of the regulatory authority to assess the compliance of each participant and impose penalties in the event of non-compliance. The environmental integrity of the program requires that compliance be assessed for each participant annually. The intensity of the scrutiny of a given participant in a given year can be varied to keep the administrative costs reasonable.

It is important for the liquidity of the market, and hence economic efficiency, that compliance of all participants be assessed quickly (within 6 to 12 months) after the end of the grace period. Otherwise participants will hold extra allowances in anticipation of possible compliance needs, thus reducing liquidity. Automatic penalties, which can be appealed, improve liquidity as well. The penalty for non-compliance is clearly defined and is automatically imposed, like a parking ticket, but can be reduced if successfully appealed. Otherwise participants found to be in non-compliance will hold extra allowances or credits in anticipation of the possible penalty until the appeals are exhausted.

5.7 Compliance Period, Allowance Life, Borrowing, Banking, Safety Valve and Non-Compliance Penalty

The compliance period is the interval at which participants must demonstrate compliance -- submit allowances or credits equal to their actual emissions. It is recommended that the compliance period be a year. Participants should have a reasonable period (60 to 90 days) after the end of the compliance period to report their actual emissions and a short grace period (30 to 60 days) to submit the necessary allowances or credits.

The regulatory authority could specify the same compliance period, the calendar year for example, for all participants. Alternatively participants could be assigned to, or be permitted to choose, their own compliance periods provided that the period is no longer than 12 months. RECLAIM assigns participants to one of two compliance cycles, while all other programs have a single, usually calendar year, compliance period for all participants. Multiple compliance periods may result in a more uniform workload for the regulatory authority.

Allowance life is the period of time an allowance remains valid for compliance use. It is recommended that an allowance remain valid until it is used for compliance, cancelled by the owner, or cancelled by the regulatory authority as part of a non-compliance penalty. A limited life, say 10 years, for allowances or credits makes no difference in practice beyond a few years since the oldest allowances can be used first for compliance. A short life, say 2 or 3 years, could restrict banking in an unpredictable manner. Limits on banking are recommended below, so a short allowance life is not needed for this purpose.

Borrowing allows a participant to use allowances issued for a future period for compliance during the current period.[45] This means that the participant currently has insufficient allowances but expects to have surplus allowances in the future. The risk is that the participant ceases to operate before the borrowed allowances are repaid through lower emissions. This risk is borne by the environment in the form of higher emissions than would otherwise occur.

Brokers can structure contracts that are equivalent to borrowing -- purchase of allowances for the current period and a forward contract for the sale of allowances for a future period. This has a cost to the participant, but the cost reflects the compliance strategy adopted by the participant.

No existing trading program allows borrowing. Some proposed trading programs for greenhouse gases would allow a limited amount of borrowing under very restricted conditions with a requirement to repay more than the borrowed allowances (i.e., to pay interest on the borrowed allowances). It is recommended that borrowing not be allowed for any of the substances.

Banking allows surplus allowances to be saved for use in a later compliance period. Banking improves economic efficiency by increasing the liquidity of the market and enabling a more gradual adjustment to reductions in emissions targets. Banked allowances represent emission reductions. Typically the reductions are made when total emissions are higher than when the allowances are used. This may yield an environmental benefit. On the other hand, the existence of a large bank may delay emission reductions after the emissions target has been reduced and so delay environmental benefits.

It is recommended that unlimited banking be allowed for SOx, NOx and GHG allowances or credits but with provisions to limit the quantity banked or the use of banked allowances or credits.[46] The "flow control" provisions of the Ozone Transport Commission NOx Budget program discounts any banked allowances used by 50% if the bank exceeds 10% of allowable emissions. Accumulation of a large bank of allowances or credits is unlikely unless the cost of emission reductions is lower than anticipated. Discounting banked allowances and credits under those conditions transforms some of the cost savings into an environmental benefit.

A specific recommendation on how to limit the size of the bank or the use of banked allowances and credits is not offered. There are numerous possible options and they require analyses beyond the scope of this document. Since the environmental impacts differ by substance, the limits on banking can also differ, being progressively more generous for NOx,

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[45] Borrowing is not possible in a baseline and credit design.

[46] Assume that a limit of 10% of the allowable emissions is adopted for banking of NOx allowances/credits. A provision to limit the quantity banked would cancel surplus allowances/credits on a pro rata basis so that the bank did not exceed this limit. A provision to limit the use of banked allowances/credits would allow all surplus allowances/credits to be banked, but it the size of the bank exceeded the limit multiple (for example 2) banked allowances/credits would need to be submitted to cover one tonne of NOx emissions.

SOx and GHGs. Any provision(s) to limit banking should be designed so that early emission reductions are still rewarded.

Emissions trading limits aggregate emissions to the emissions cap. But the cost of meeting that cap is uncertain. A "safety valve" can limit the cost of compliance in the event of unforeseen circumstances, such as the dramatic increases in RECLAIM NOx prices due to the California electricity shortages. Under a "safety valve", the regulatory authority agrees to issue as many additional allowances as necessary to achieve compliance at a relatively high pre-specified price. This caps the compliance cost, but with some risk to the environment.[47] A "safety valve" and flow control or discounting of banked allowances can be seen as means of sharing the risk between trading program participants and the environment.[48]

The intended non-compliance penalty is often triple the price of an allowance.[49] To protect the environment and ensure that the penalty is always higher than the price of an allowance, the penalty should involve a reduction of the participant's allowance allocation for the next year equal to the excess emissions, assuming that allowances are distributed free. The loss of allowances combined with a financial penalty roughly equal to double the allowance price yields a non-compliance penalty roughly triple the allowance price. Penalties should be automatic with provisions for appeal.[50]

5.8 Emission Reduction Credits and Links to Other Trading Programs

Credits for emission reductions by sources outside the trading program and allowances from other trading programs may cost less than Alberta allowances and so reduce compliance costs for participants. However, a trading program should allow the use of such credits and allowances only if the effect on the Alberta airshed is equivalent to a reduction by a program participant.

It is believed that the net inflow of SOx and NOx from neighbouring airsheds in British Columbia and the northwestern United States is small. Use of credits created by SOx or NOx emission reductions in neighbouring jurisdictions should not be allowed unless the proponents can demonstrate a benefit to the Alberta airshed. If a benefit to the Alberta airshed is demonstrated and the source that implements the emission reductions participates in an emissions trading program, the corresponding allowances must be transferred to Alberta or be cancelled to preserve environmental integrity.

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[47] With very high prices there may also be non-compliance, as was the case in RECLAIM, so the extra risk to the environment is probably less than the number of allowances issued under the safety valve provision.

[48] With low prices the flow control or discount on banked allowances benefits the environment. With high costs the safety valve reduces the environmental benefit.

[49] The draft EU Emissions Trading Directive set the penalty higher than the projected cost of geological sequestration of CO_2, so that this high-cost option would be more attractive than non-compliance.

[50] This differs from most environmental penalties, which require conviction first. That process often does not punish minor offences and allows offenders to delay the imposition and to negotiate the size of penalties. Those practices undermine the environmental integrity of an emissions trading program.

Credits for emission reductions by SOx and NOx sources in Alberta but outside the trading program could be accepted. American programs for the creation of NOx credits have had mixed reviews.[51] And the scope for generating such credits in Alberta is limited. The trading program would cover an estimated 95% of the provincial SOx emissions and 75% of the provincial NOx emissions. Most of the remaining NOx emissions are from transportation sources. Development of an emission reduction credit program can be costly. To keep this cost to a minimum given the limited potential for reductions by non-covered sources in Alberta, it is recommended that no provision be made for the use of SOx credits for reductions outside the trading program and that NOx credits be limited to mobile source reductions in the province. It is recommended further that only a methodology approved by the U.S. Environmental Protection Agency, but adapted to Alberta if necessary, be accepted for mobile source NOx credits.

A GHG trading program should include provisions for the use of credits from Alberta sources for emission reductions by sources outside the program and for sink enhancement measures. GHG emission reductions anywhere in the world yield the same environmental benefit. Thus, cost minimization suggests that participants should be permitted to use credits or allowances from other jurisdictions for compliance with their obligations in Alberta provided that environmental integrity is preserved. Other policy considerations, however, suggest geographic or other restrictions on the use of imported credits or allowances.

If Alberta chooses to accept GHG credits and allowances from other jurisdictions for compliance purposes, they should meet standards comparable to those set for Alberta emission reduction and sink enhancement actions. If another jurisdiction has a GHG emissions trading program, an efficient way to enable the use of credits or allowances from that jurisdiction is to link it with the Alberta trading program. This would enable participants in both programs to use allowances and credits from either program for compliance purposes.

The federal government has stated that it plans to implement emissions trading for GHG emissions by large industrial sources to help meet its commitment under the Kyoto Protocol. It appears that this trading program will be implemented by negotiating emission reduction covenants with industry sectors. The coverage is likely to be similar to that recommended in this document for the Alberta emissions trading program. However, the emission reduction targets (distribution of allowances) and design features of the federal program could be quite different from those recommended in this document or that might ultimately be adopted for an Alberta-based GHG trading program.

Mandatory participation by Alberta firms in both a federal and a provincial GHG trading program is undesirable. The federal and Alberta programs would probably have different prices for an allowance, so participants could face two different prices for CO_2 emissions.

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[51] See Environmental Law Institute and U.S. Environmental Protection Agency, 2002b.

Compliance with the more stringent program's requirements would probably lead to compliance with the other program's requirements as well.[52] But there would still be administrative costs to both the participants and the regulatory authority of the less stringent program.

It is highly desirable that if a federal GHG emissions trading program is implemented that the Alberta program be linked with, or transition to, the national program. It is generally possible to link emissions trading programs despite significant differences in their design.[53] However, linking established programs creates winners and losers in each program and so may be politically difficult. Allowance prices in the programs are likely to be different before they are linked. Then the buyers in the high price program and the sellers in the low price program benefit from the link. Conversely, the sellers in the high price program and the buyers in the low price program are adversely affected by the link.

If an Alberta and a federal trading program are developed at the same time it would be better for the participants if both governments co-operated in the design of a single program that meets the goals of both governments. If an Alberta program is implemented first, it would be better for the participants subject to both programs, that the Alberta program be linked with or transition to a national program.

If negotiated sectoral agreements are the basis for implementing emissions trading, it is important that the agreements with the different industry sectors facilitate trading of allowances or credits between participants in different industries and, where appropriate, with sources in other jurisdictions. If trading among industry sectors is restricted by rules, approval requirements, transaction costs, or other provisions the potential cost savings will not be realized.

5.9 Recognition of Early Emission Reductions

An early emission reduction is one that occurs prior to the start of the first compliance period of the trading program. Two types of early emission reductions are possible -- reductions implemented at a participating facility and those implemented at a non-participating source.

The treatment of reductions implemented at a participating facility depends upon the allocation procedure adopted. If an output-based allocation is adopted with the same allocation rate for all participants in a given industry sector, it can be argued that early reductions are automatically recognized. The early reductions give the participant a larger allocation relative to its actual emissions. An auction also recognizes a participant's early reductions because its actual emissions and the quantity of allowances it needs to buy are lower.

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[52] If all of the participants in the Alberta GHG program were also participants in the federal GHG program, the price of the allowances/credits for the program with the less stringent target might fall to zero. However, there might be differences in coverage or other factors that would result in a positive price for the allowances/credits of both programs.

[53] See Haites and Mullins, 2002.

Only entity grandfathering requires special treatment of early reductions by a participant. The effect of reductions prior to the date selected as the basis for the allocation is not recognized. The decision on the time period, if any, during which early reductions are given recognition is arbitrary. The longer that period, the less likely that participants will be able to document their early reductions. Flexibility in the definition of the base period may be an alternative. Thus, participants could select their highest annual emissions during a specified multi-year period as the basis for the allocation with no other recognition for early reductions.

Some Alberta entities have helped finance emission reductions at sources that would not be covered by the trading program. So far as is known these actions are limited to GHG reductions, but many of the reductions have been implemented in other provinces and countries. Which of these reductions, if any, should be recognized toward compliance with obligations under an Alberta emissions trading program? In the case of GHG emissions recognizing these reductions does not raise environmental concerns provided they can be demonstrated to represent reductions that would not otherwise have been made.

Alberta's climate change action plan promises to develop a definition for eligible GHG offsets. Such a definition would largely answer the question, but it is not yet available. In the absence of such a definition, three considerations can be applied to help determine which of these reductions to recognize:

- Alberta's climate change action plan emphasizes domestic investment in technology, research and development over purchases of international emission permits;
- as a participant in the GERT pilot project, Alberta indicated a willingness, but not a commitment, to recognize GHG reductions registered by that project; and
- a link with another GHG trading program will likely require agreement on the acceptable early reductions.

These considerations suggest recognition of the GHG reductions registered by GERT unless a link with other GHG trading programs allows recognition of other early reductions.

5.10 Integration of Emissions Trading With Other Policies

In its approvals of two new coal-fired electricity generating stations, the Alberta Energy and Utilities Board has imposed requirements to offset the greenhouse gas emissions to the level equivalent to a combined-cycle natural gas plant.

These coal-fired stations should be treated as natural gas fired stations for the purposes of GHG allowance allocation under the emissions trading program. If the offsets have not yet been purchased prior to implementation of the emissions trading program, they will need to acquire additional allowances since their actual emissions are likely to be higher than the allocation received. If the offsets are acquired prior to the implementation of the emissions trading program, the stations could be allowed to use them for compliance with the requirements of the emissions trading program as well. Then the stations would submit a combination of offsets and GHG allowances equal to their actual emissions.

For future plants this could be addressed by treating all fossil-fired generating stations as natural gas plants for purposes of distributing GHG allowances.

Seven Power Purchase Agreements (PPAs) govern a substantial fraction of the electrical generating capacity in Alberta. Under a PPA, an electricity wholesaler buys the output of a generating unit and bids it into the market. The wholesaler then instructs the owner to operate the unit in a manner that will fulfill its successful bids. The owner of the unit is paid the fixed and operating costs specified in the PPA for the operation of the unit.

How costs for compliance with environmental regulations are treated is not clear under the PPAs. This is the case for any environmental regulation, not just emissions trading. A few of the agreements will terminate before a trading program is likely to start, but some will remain in effect until 2020. Either the wholesaler or the plant owner could be the participant in an emissions trading program. The wholesaler determines when the plant is run and so affects total emissions. The unit owner will be able to affect emissions through operating and maintenance practices. Responsibility for installing emission controls and the associated costs is not clear.

An initial review of the issues concluded that "[a]lthough emission trading could be made to work with PPA contracts in place, much analysis would be required to determine if it would work efficiently, how best it should be implemented, and how it would compare to a command and control approach. The particular nature of the PPA contracts, including the pass-through of new costs from plant owners to PPA buyers, would likely constrain emission trading and dull the incentives for cost minimization."[54]

The implications of emissions trading for Power Purchase Agreements will need to be analyzed and resolved as part of the design of a trading program. The ideal solution would provide incentives to both the unit owner and the wholesaler to reduce emissions.

5.11 Issues Related To Output-Based Baselines and Distribution Of Allowances

Free distribution of allowances or baselines tied to output raise several issues. A physical measure of output is needed for each participant. And a method for distributing allowances, or setting baselines, equitably across sectors is required. These requirements affect the definition of a sector.

Some industries have a reasonably homogeneous product; kilowatt hours of electricity in the case of electricity generators, for example. Other industries, such as petroleum refineries, produce a number of products and the mix may differ from plant to plant. Thus, it may be difficult to find a physical measure of the output of each participant. Defining participants as individual facilities will help because the output of a plant tends to be more homogeneous than that of a firm. But that doesn't resolve all of the difficulties.

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[54] Joseph Doucet Economic Consulting Inc., 2002, Executive Summary.

Why not use the value of output as the measure of output? The reason is that emissions are not related to the value of output and this measure is open to manipulation. A kilowatt hour has a different value depending upon when it is generated, but for a given generating unit the emissions per kilowatt hour are the same regardless of when it is generated. Distributing allowances on the basis of the value of electricity sold would reward actions that shift operation from low to high price periods, which may have undesirable impacts on the electricity market. Using kilowatt hours as the basis for the allocation rewards actions that lower emissions per kilowatt hour generated, the desired incentive.

Distributing allowances based on the value of output would reward participants for contracting out portions of the production process. The value of the final output would not change. Emissions by the participant would be lower but the participant would simply have shifted production activity and emissions to another location. If all emissions sources were covered, the shifted emissions would still come under the overall emissions target for the trading program. However, emissions by small sources and sources in other jurisdictions may not be covered. In any case, it is better to reward emission reduction actions than emission shifts.

Why not use a measure of input rather than a measure of output? Crude oil input could be used for refineries and energy input could be used for many sectors. Energy input is used for the US Acid Rain program and for the Ozone Transport Commission NOx Budget program. For greenhouse gases energy input would need to be adjusted for sectors that have process emissions -- cement, lime, and adipic acid production. More importantly, an allocation based on energy input would not reward improvements in energy efficiency.[55] These are actions that are expected to yield substantial, low cost GHG emission reductions. The fact that efficiency improvements are not rewarded is less serious for SOx and NOx where the main options are fuel switching and treatment of emissions.[56]

In summary, a physical measure of output is strongly preferred to an economic measure of output or a measure of input. Such measures may be difficult to define for some sectors, but the UK climate change levy agreements specify output measures for over 50 industry sectors and sub-sectors. In addition, the Netherlands has energy efficiency covenants with a number of industry sectors that use physical measures of output. Japan has a voluntary emission reduction program under which firms report changes in emissions per unit of output and use physical output measures in many industry sectors.

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[55] Assume that a plant uses 100 units of energy input and produces 25 units of output. An energy efficiency action would enable the plant to produce 30 units of output with the same 100 units of energy input. Since the number of allowances received is based on energy input, the energy efficiency action is not rewarded. If the allocation is based on output it is rewarded. Assume the plant gets 4 allowances per unit of output. Then its allocation rises by 20% as a result of the energy efficiency actions.

[56] An allocation based on energy input would encourage participants to switch from fossil fuels to electricity. The total energy input (and resulting allocation of allowances) might drop somewhat, but the participant's emissions would drop to zero because the electricity generator is responsible for the emissions associated with electricity generation. This would shift emissions among participants covered by the trading system and so may not change total emissions. However, it could increase electricity prices.

A physical measure of output means that it is difficult to compare equity across sectors. Is 0.5 kg CO_2e per kWh more or less generous than 3.6 kg CO_2e per tonne of clinker? Two approaches can be used to address sectoral equity for greenhouse gas emissions.[57] One approach is to use world best practice to set the relative allocations for each sector.[58] The world best emission rate is applied to the output for each sector and the resulting allocations are scaled up to the total cap. This requires agreement on the world best practice for each sector, which will be contentious. Also, it may be difficult to apply to oil sands operations. To achieve equity within a sector the allocations to all participants within a sector would be based on the world best practice.

An alternative approach is to calculate the emissions per unit of output for each sector after all economically attractive emission reduction measures are implemented and to use this to set the relative allocation for the sector. This requires an independent assessment of the economically attractive emission reduction measures for each sector or participant, which can be time consuming and costly. The definition of what is economically attractive may also be contentious. This approach was used to set the emissions targets in the UK climate change levy agreements.

A sector, then, is a group of participants with the same unit of physical output. In some cases, such as cement, this will correspond to the standard industry definition. In other cases, an industry may include several sectors; the chemicals industry may include fertilizer plants, ethylene plants, and other sectors. Since the individual plants are the trading program participants, the allowance distribution process can accommodate multiple sectors within a single industry.

Finally, there will be sectors with a common output, but different production processes with substantially different emissions. Coal-fired and natural gas fired electricity generation are one example. Since the emissions per unit of output are significantly different using a common allocation rate for the processes leads to a penalty for the higher emitting process and a windfall profit for the lower emitting process -- coal-fired generators would be penalized while their gas-fired competitors would be rewarded. In such cases, it is recommended that the different production processes be treated as separate sectors. However, developers of new facilities should be encouraged to adopt the lower emitting technology, so all new plants would be included in the lower emitting sector. Thus, existing coal-fired plants would be a separate sector, but all new fossil-fired generating units would be part of the gas-fired sector regardless of whether they used coal or gas. This is equivalent to the offset requirement for GHG emissions imposed on the new coal-fired generating units, but it would apply to SOx and NOx emissions as well. This has the effect of setting the emissions standard for new generating units as the emissions associated with a gas-fired unit, but allows coal-fired units to be built provided they can offset the extra emissions.

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[57] These approaches do not work well for SOx or NOx emissions. The reason is that the emission reduction measures for SOx and NOx focus on the fuel characteristics and control technologies and the percentage reductions achieved by control technologies are quite large (60% to 95%). The world best SOx practice may reflect coal characteristics that differ from those available in Alberta and/or relative coal and natural gas prices that differ from those in Alberta. Analysis of the economically attractive emissions control options may identify some plants where installation of a scrubber is justified and others where a scrubber is uneconomic. The former would receive allocations based on 5% of their existing SOx emissions while the latter would get allowances based on 100% of their current emissions. That is unlikely to be considered fair. Although not as dramatic, the situation is similar for NOx emissions.

[58] The energy efficiency targets in the Netherlands are related to world best practice; see Phylipsen et al., 2002.

Conventional oil production and oil sands facilities may be another situation where two processes yield the same output but where separate sectors are warranted due to differences in the emission rates. As in the electricity example, it may still be desirable to include all new facilities in the lower emitting sector -- so new oil sands facilities would get allocations equal to conventional oil production facilities. The implications of this possibility need to be further analyzed as part of the detailed design.

5.12 Issues Related to Entity Grandfathering of Allowances

Entity grandfathering distributes allowances to participants that existed at the time the trading program is introduced based on their emissions during a previous year or period.[59] Entity grandfathering requires decisions on the allocations received by new participants and by participants that cease to operate. RECLAIM and the US Acid Rain program do not allocate any allowances to new participants and continue to allocate allowances to participants that cease to operate.

Other programs allocate allowances to new participants. A reserve for new participants is withheld from the overall allocation. The allocation is based on the lowest achievable emissions or other estimate of the participant's emissions. The treatment of new participants has no effect on environmental integrity (as long as the total cap is not increased) and little impact on efficiency. It is primarily an equity issue and so is a policy decision.

Since the allocation to a participant does not change with output, withdrawing the allocation from a participant that ceases to operate creates an incentive to continue to operate at a minimal level. Continued allocation to participants that cease to operate removes that incentive, but may be seen to be unfair by new participants who end up buying those allowances. Unless the allowances are very valuable, the incentive to continue minimal operation will not be strong relative to the costs of operating the facility. A compromise that would address the incentive issue would be continued allocation for a limited period of time, such as two to five years.

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[59] The distribution could be based on emissions during a specified year, e.g., 2002; average annual emissions during a period, e.g., 2001 through 2003; the highest annual emissions during a period, e.g., highest of 2001, 2002 or 2003 emissions; or various other definitions of past emissions. A period, rather than a specific year, is often used to reduce the impact of unusual economic conditions or specific events, such as a strike or major repairs.

Regardless of the year or period chosen as the basis for the allocation, some participants will argue that they had implemented emission reduction actions prior to that time which reduced their emissions relative to those of their competitors. If they do not receive recognition for those early reduction actions in the form of an upward adjustment to their emissions their early action to benefit the environment will be penalized in the form of a lower allocation of allowances while their competitors are rewarded for their inaction. As discussed in section 5.9 above any formula for recognition of early reduction actions is arbitrary.

5.13 Implementation Of Emissions Trading

Implementation of emissions trading for SOx, NOx and GHG emissions by large industrial sources in Alberta will require resolution of many issues, including:

- Emissions caps: the cap for emissions of each of the substances by trading program participants for the first five to ten years of the program and provisions to limit actual SOx and NOx emissions by participants to prevent occurrence of "hot spots".

- Coverage: the minimum emissions by substance and minimum design size by sector for trading program participants as well as the emissions within each type of facility covered by the trading program.

- Monitoring and Reporting: the monitoring equipment each participant must install for each emissions source, the requirements for testing the accuracy of the monitoring equipment, penalties having inaccurate monitoring equipment, adjustments for missing or inaccurate data, and reporting requirements (e.g., frequency and nature of the electronic reports).

- Baselines/Distribution of Allowances: whether to adopt a baseline and credit or cap and trade design and whether the baseline or allowance allocation will be related to historic emissions (grandfathering) or current output. In the case of an output-based allocation or baseline, the sector definitions, the output measure for each sector and the approach for achieving sectoral and entity equity will need to be decided. In the case of entity grandfathering, the treatment of new sources, participants that cease operation and credit for early action will need to be resolved.

- Program Design Features: banking, borrowing, instrument life, compliance period, opt-in provisions, non-compliance penalties, safety valve, liability regime.

- Links to Other Policies: implications for power purchase agreements, treatment of offset requirements for new coal-fired generating stations, tax treatment of allowances, market oversight.

- Project Credits and Links to Other Programs: which types of project-based credits from which jurisdictions are eligible for SOx, NOx and GHGs and how to link GHG trading to trading programs in other jurisdictions.

- Registry: a registry will need to be developed or registry services will need to be contracted.

Recommendations on several of these items are part of this document. However, more detailed work remains on many items.

Alberta has launched a process of negotiating sectoral emission reduction agreements as part of its climate change action plan. The agreements will include regulatory backstops, financial consequences for non-participation, and reporting requirements. This process could be used to implement emissions trading for all three substances if:

- the negotiations were expanded to cover SOx and NOx as well as GHGs and the emission reduction targets for all three substances were assigned to specific facilities (if the negotiations established the baselines or distribution of allowances to individual facilities);

- large facilities covered by the agreements are allowed to achieve their emission reduction targets through emissions trading and the relevant agreements include a standard annex setting out the rules for emissions trading;

- the monitoring and reporting provisions are consistent with the needs of an emissions trading program as opposed to compliance with a sectoral agreement; and

- other policies are adjusted as necessary and a registry is put in place.

This is similar to the manner in which the United Kingdom implemented its trading program for entities covered by climate change levy agreements and it appears to be the approach the federal government plans to use to implement emissions trading for GHGs. However, it would probably require much more preparation and coordination among agreements than may be required for the negotiation of sectoral reduction agreements restricted to greenhouse gases.

Experience in the US and the UK with the introduction of emissions trading programs suggests detailed design and associated legislation/regulations require 18 to 36 months and that the first compliance could begin 6 to 12 months later. This suggests that an emissions trading program in Alberta is unlikely to start prior to 2005 to 2007.

Estimates of the cost of implementing an emissions trading program are difficult to find. Any figures must be interpreted with care. The costs may be the historic costs of implementing the program. They may not include fixed costs such as office space and management time. During the program design, the South Coast Air Quality Management District estimated that

RECLAIM would require about 5% of the District's budget.[60] The Director of the U.S. Acid Rain program, on the other hand, claims that the cost of that program are far lower than the cost of a comparable regulatory program.

The U.K. government has recently published estimates of the cost of developing its greenhouse gas emissions trading program. Those estimates are provided in Table 11. The total cost has been over $4 million although the program is much larger (over 40 sectoral agreements and over 5,500 participants) and more complex than the proposed Alberta trading program. About 45% of the total cost was for development and maintenance of the registry. It might be possible to obtain the registry service at lower cost from an established provider.

Table 11: Administrative Costs of Developing the U.K. Greenhouse Gas Trading Program

	Cost	
	(£,000)	($,000)
Staff costs	£560	$1,300*
Consulting services	£445	$1,000*
Registry design and build	£690	$1,600*
Registry maintenance	£120	$300*
Total	£1,815	$4,200*

Note: * Costs in Canadian dollars are rounded to the nearest $100 and so do not sum to the total.

Source: U.K. DEFRA, 2002, p. 26.

5.14 Recommendations

If an emissions trading program is implemented, it should cover as large a share of the total emissions as possible. As such, it should include any facility whose annual SOx, NOx or GHG emissions exceeds a specified emissions threshold or whose capacity exceeds the specified design capacity for that type of facility. A facility that exceeds any of the thresholds should be required to participate in the program for all of the substances.

Participants with compliance obligations should be individual facilities -- a facility located on a single contiguous site or operated independently -- such as an electricity generating unit, natural gas plant, oil refinery, cement plant, etc. Any person or entity should be allowed to buy or sell allowances and credits. The owner of an allowance or credit may request the regulatory authority to cancel the allowance or credit to benefit the environment.

An emissions trading program should seek to cover as many of the sources as possible within any facility that meets the threshold for participation. But it must be possible to measure or calculate the emissions of each source with reasonable accuracy at reasonable cost. Vehicle emissions are generally excluded, but the emissions of vehicles used in oil sands and mining operations should be included if they can be measured or calculated.

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[60] U.S. Environmental Protection Agency, 2002a, p.30.

An emissions trading program should require participants to install the most accurate type of monitoring equipment, often continuous emission monitors; to regularly test the accuracy of the monitoring equipment; and to replace missing or erroneous readings with upwardly biased estimates.

The compliance period should be a year. Participants should have 60 to 90 days after the end of the compliance period to report their actual emissions and 30 to 60 days after the reporting deadline to submit the necessary allowances. The regulatory authority could set the same compliance period for all sources or allow participants to have different compliance periods.

The performance of the monitoring equipment, reported emissions (including adjustments for missing data) and the validity of the allowances or credits used for compliance must be verified by the regulatory authority or accredited experts each year. Compliance should be resolved within 6 to 12 months after the end of the grace period.

Borrowing should not be allowed. Banking should be allowed, but with "flow control" or discounting of banked allowances and credits if the quantity of banked allowances/credits becomes relatively large. A "safety valve" provision that allows the regulator to issue additional allowances at a relatively high pre-specified price should be included in the design.

To protect the environment and ensure that the penalty is always higher than the price of an allowance, the penalty should involve a reduction of the participant's allowance allocation for the next year equal to the excess emissions, assuming that allowances are distributed free. The non-compliance penalty should also include a significant financial penalty. Penalties should be automatic with provisions for appeal.

Since the trading program would cover about 95% of total SOx emissions, no provision should be made for the use of credits for reductions by sources outside the program. Most of the NOx emissions not covered by the trading program are from transportation sources. Thus, it is recommended that only NOx credits created by mobile source reductions in Alberta be accepted. Further, it is recommended that only a methodology approved by the U.S. Environmental Protection Agency, but adapted to Alberta if necessary, be accepted.

The GHG trading program should include provisions for the use of credits from Alberta sources for emission reductions by sources outside the program and for sink enhancement measures. GHG credits and allowances from other jurisdictions could also be accepted, but they should meet standards comparable to those set for Alberta emission reduction and sink enhancement actions. If another jurisdiction has a GHG emissions trading program, an efficient way to enable the use of credits or allowances from that jurisdiction is to link it with the Alberta trading program. This would enable participants in both programs to use allowances and credits from either program for compliance purposes.

If a national GHG emissions trading program is implemented, it is highly desirable that an Alberta GHG trading program be linked with, or transition to, the national program. If an Alberta and a national trading program are developed at the same time it would be better for the participants if both governments co-operated in the design of a single program that meets their respective goals. If an Alberta program is implemented first, it would be better for the participants subject to both programs, that the Alberta program be linked with or transition to a national program.

Recognition of early emission reductions at participating facilities should be addressed as part of the allowance allocation. Some Alberta entities have helped finance GHG emission reductions at sources that would not be covered by the trading program. Recognition of early GHG emission reductions at sources outside the trading program should be limited to those registered by GERT unless a link with other GHG trading programs allows recognition of other early reductions.

The implications of emissions trading for Power Purchase Agreements will need to be analyzed and resolved as part of the design of a trading program. The ideal solution would provide incentives to both the unit owner and the wholesaler to reduce emissions. The CO_2 offset requirements imposed by the Energy and Utilities Board on two new coal-fired generating stations will need to be integrated with a GHG emissions trading program.

If allowance allocations or baselines are tied to output, a physical measure of output is strongly preferred to an economic measure of output or a measure of input. Sectors consist of participants with the same unit of physical output. Achieving intersectoral equity is difficult because the sectors have different output measures. Options to address intersectoral equity exist for GHGs, but they do not work well for SOx and NOx. Although they have the same output, existing coal- and gas-fired generating units should be considered different sectors. All new fossil-fired generating units should be treated as gas-fired units.

If allowances are distributed free to participants that existed at the time the trading program is introduced based on their emissions during a previous year or period, decisions are required on the allocations, if any, to new participants, the continued allocation of allowances to entities that cease to operate, and recognition, if any, of emission reduction actions prior to the base year or period. These are primarily equity issues.

Implementation of emissions trading for SOx, NOx and GHG emissions by large industrial sources in Alberta will require resolution of many outstanding issues. Such a trading program could be implemented through the sectoral emission reduction agreements currently being negotiated as part of its climate change action plan. However, it would probably require much more preparation and coordination among agreements than may be required for the negotiation of greenhouse gas emission reduction agreements. Experience elsewhere suggests that an emissions trading program in Alberta is unlikely to begin operation prior to 2005 to 2007.

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7. Appendices

7.1 Contents

The Appendices include a glossary and three separate documents. The document titles and the project team consulting firms responsible for each of the documents is provided in the table below. These documents provide context valuable in understanding the results presented in the main summary document.

Titles of Appendices and Project Team Consulting Firm Responsibilities

Titles	**Project Team Consulting Firms Responsible**
APPENDIX A: MARKAL Results	HALOA Inc.
APPENDIX B: Costs of Technologies to Reduce NOx and SOx Emissions From Industrial and Electric Power Generation Sources in Alberta	Cheminfo Services Inc. Clearstone Engineering Inc.
APPENDIX C: Profile of Criteria Air Contaminants, Mercury and Greenhouse Gases Emissions in Alberta	Cheminfo Services Inc.

Glossary

A	
ACT:	Alternative Control Techniques
AENV	Alberta Environment
AMG:	Analysis and Modelling Group
AS+S	Amine Scrubbing and Storage
B	
BAT:	Best Available Technology (BAT)
C	
CEM:	Continuous Emissions Monitoring
CO_2:	Carbon Dioxide
CUECost:	Coal Utility Environmental Cost
D	
DCE:	Dichloroethane
DLS:	Dry Lime Scrubbing
E	
EPA:	U.S. Environmental Protection Agency
EPG:	Electric Power Generation
F	
FCCU:	Fluidized Catalytic Cracking Unit
G	
GHG:	Greenhouse gases
GJ:	Gigajoule
H	
H_2S:	Hydrogen sulphide
I	
IAPCS:	Integrated Air Pollution Control System Program
IGCC:	Integrated Gasification Combined Cycle
IIOC:	Improved Combustion Air, Instrumentation, Operator Care
IPCC:	Integrated Pollution and Prevention Control
K	
kW:	kilowatt

L

LEA:	Low Excess Air
LIFAC:	Limestone Injection in Furnace With Activation Chamber
LIMB:	Lime Injection Multi-Stage Burner
LNB:	Low NOx Burner
LNCFS:	Low NOx Concentric Firing System
LOI:	Loss on Ignition
LSD:	Lime Spray Drying
LSFO:	Limestone Scrubbing (Forced Oxidation)

M

MDF:	Medium Density Fibreboard
MDI:	Methylene Diparaphenylene Isocyanate
MKF:	Mid-Kiln Firing
mmBTU:	Million British Thermal Unit
mmfbm:	Million foot board measures
MWh:	Megawatt hour

N

NAICS:	North American Industrial Classification System
NCCP:	National Climate Change Process
NGCC:	Natural Gas Combined Cycle
NGR:	Natural Gas Reburn
NGSC:	Natural Gas Substitution for Coal
NMHC:	Non-methane hydrocarbon
NOx:	Nitrogen Oxides

O

OFA:	Over-Fired Air
OSB:	Oriented Strandboard

P

PM:	Particulate Matter
PPA:	Power Purchase Arrangement

S

SAGD: Steam Assisted Gravity Drainage
SCR: Selective Catalytic Reduction
SIC: Standard Industrial Classification
SMR: Steam Methane Reforming
SNCR: Selective Non-Catalytic Reduction
SOx: Sulphur Oxides
S-PLY: Softwood Plywood
SRU: Sulphur Recovery Unit

T

TRS: Total Reduced Sulphur
TWh: Terawatt-hours

U

UF: Urea Formaldehyde
US: Capture and Underground Storage

V

VOC: Volatile Organic Compound

CHEMINFO

Alberta Environment Emission Trading Project

Major Feasibility Study

Preliminary Analysis & Discussion Document

APPENDIX A:

MARKAL Results

March 2003

Submitted to:
Alberta Environment

Prepared by:

HALOA INC.
Montréal, Québec
Canada

Introduction

Objectives

There are three objectives to this Appendix, namely:

- To present the MARKAL methodology in more detail than what is discussed in the main body of the *Preliminary Analysis and Discussion Document*. (This is useful since methodological considerations are often essential for correct interpretation of the model's results).
- To discuss the calibration of the Base case as represented in MARKAL-Alberta, including the main assumptions made for the Baseline. The Base case uses the same basic techno-economic assumptions that were used in the North American MARKAL model for the analysis of the National Process scenarios performed for the Analysis and Modeling Group in 2002. In addition, the model has been equipped with NOx, SOx, and Mercury emission coefficients derived from the *Profile of Criteria Air Contaminants, Mercury and Greenhouse Gases Emissions in Alberta* (Appendix C) produced as part of this project. The main Base case results are found in section 3.
- To exhibit and briefly discuss the results on a series of model runs constituting Cases 1 to 8. One of these runs was made for the purpose of calibrating the model (Base case), four others to explore the range of potential emission targets without any consideration of policy modeling (cases 2 to 5), three others for modeling specific permit trading systems (Cases 4a, 6, 7). Case 8 is sensitivity variant of case 7, where the price of natural gas was assumed significantly higher, but otherwise modeling the same permit trading assumptions as case 7.

The rest of this Appendix consists of the following four parts:

- Part I: Methodology and Calibration;
- Part II: Exploratory Runs;
- Part III: Policy Runs, and
- Part IV: Natural Gas Price Sensitivity.

All monetary units used in the Appendix A are 1995 C$, unless specified otherwise.

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1. Methodology and MARKAL Calibration

1.1 The MARKAL Model and its Adaptation for Alberta-Alone

The MARKAL model is a technology-explicit dynamic bottom-up model of an energy-industrial system, covering all sectors that produce, transform, distribute or consume energy. The model distinguishes a large number of energy forms at all levels of the energy system (primary, secondary, and final energy forms). The planning horizon is divided into several 5-year periods, linked by the technology specific capital dynamics.

MARKAL is driven by more than 50 demands for energy services (useful energy) in all end-use sectors (industries, transportation, residential and commercial). These demands are in turn sensitive to their own production costs, thanks to a set of user-selected own price elasticities. The energy industries (primary extraction, processing, electricity production), are driven by the end-use sectors' energy requirements and by the exports dynamics. In a multi-regional setting (such as the one in the North American MARKAL model), exports by one region are equal to imports by other regions, and therefore even the import/export dynamics are fully endogenous to the model. In the Alberta-alone model, we have closely mimicked such a behaviour by a modeling implement described below.

MARKAL is, therefore, an equilibrium model on energy markets, and any changes in some portion of the energy system will provoke a chain of consequences on other parts of the system by means of price propagation which entails energy and process substitutions and eventually changes in the volumes and prices of the energy forms produced and consumed. The rationale used to compute the equilibrium is the maximization of the long-term net present value of the total net surplus of producers and consumers, which is akin to a profit. The model is not simply a cost-minimizing engine, recognizing that revenues play as important a role as costs in the computation of the equilibrium. An interesting property of the MARKAL equilibrium is that the maximization of the total net surplus is fully compatible with the individual maximization of each agent's profit, provided all agents use marginal cost pricing (note that by an abuse of language, MARKAL is often incorrectly called a least-cost equilibrium model).

In a Base case setting, MARKAL "picks and chooses" among the many production and consumption possibilities to compute the optimal surplus solution. In a policy scenario (e.g. a scenario with emission constraints), additional options are usually added to its database (in the form of emission reduction options), and MARKAL recomputes its optimal selection of production and reduction options with the aim at optimizing surplus while respecting the emission constraints. In computing the equilibrium, MARKAL explicitly takes into account the changes in fuel prices that may result from technology choices made by the model (note that only equilibrium models are capable of simultaneously selecting technologies while taking into account fuel price changes that occur because of technology selection).

The North American MARKAL model consists of 14 linked modules, one per province or Territory, plus a US module. The 14 modules are tightly linked by a set of trade variables, one per traded commodity (crude oil, natural gas, coal, refined petroleum products - RPP's, electricity, emission permits). Each trade variable is treated as a technology (e.g. pipeline, electricity intertie, permit market, etc.) with its own costs and investment dynamics.

The Alberta model was obtained from the Alberta module of the North American MARKAL model. In the North American (NA) model, the export and import variables between Alberta and other provinces and the US are solved for endogenously when the North American equilibrium is computed. In the Alberta-alone model, we have proceeded as follows:

- A North American MARKAL Base case (identical to the one used in the National Climate Change Process) was run and the shadow prices of bitumen, crude oil and natural gas were obtained.
- The exports of these three commodities were treated as price takers, i.e. Alberta can export freely at those prices.
- The exports and imports of electricity were fixed at the levels found in the NA equilibrium.

These modeling choices allow the Alberta model to remain as close as possible to the original North American equilibrium model. Indeed, the exports of oil and gas in the Alberta-alone model remain sensitive to an increase in production costs: if such an increase is moderate, the exported quantities will not be affected, although the profit margins will be reduced. If the production cost increases are sufficiently large, the model may indicate a reduction in exported quantities as well. In both cases, the dollar volume of exports will be reduced.

1.2 Representation of Facilities and Processes

The original Alberta module has a detailed representation of industrial processes existing in Alberta, but without specific representation of ownership, except in the Electric Power Generation (EPG) sector. This means that each process of a given sector represents the sum of all similar processes existing in that sector in Alberta.

In EPG, each existing or planned generating unit is individually represented in MARKAL, with its own investment/retirement dynamics. Future expansions not yet announced are represented by generic technologies such as: Pulverized Coal boiler unit, Integrated Coal Gasification Combined Cycle, Single Cycle gas turbine, Combined Cycle Gas Turbine (with or without cogeneration of steam), wind turbine, solar, and Biomass plants.

For the purpose of this project, base case emissions of NOx and SOx by each main Alberta facility were modeled in the following industries: Chemicals (12 facilities, further disagregated into 27 processes), Cement (3 facilities), Pulp and paper (4 facilities), Oil refining (4 facilities), and Wood products (7 facilities, one of which represents all lumber mills, and the other 6 the individual panel board facilities).

In upstream oil and gas, the data was not available at the facility level. Rather, the following 3 sub-sectors are distinguished: Oil Sands (in situ, mining and upgrading to synthetic oil), gas production and processing (including transmission), and conventional oil production.

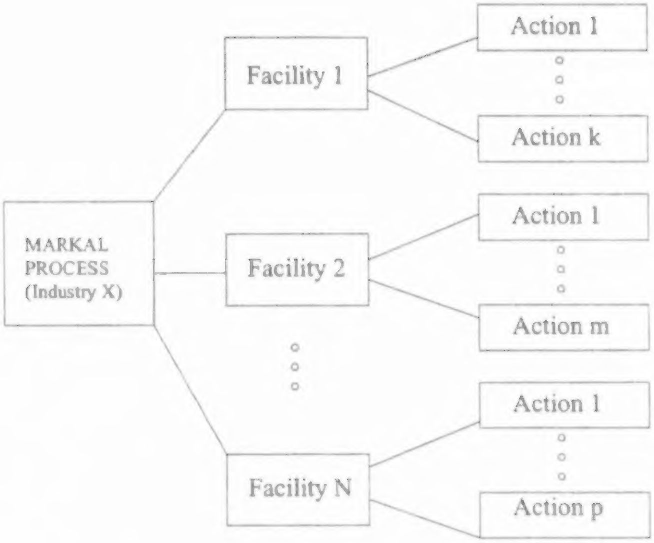
1.3 Representation of Emission Reduction Options

For each facility (or each subsector in the case of Upstream Oil and Gas - O&G), a number of options for reducing GHG's, NOx, and SOx emissions have been modeled individually. The intensity of each reduction option is directly linked (proportional) to the activity of the facility or subsector the option is attached to in the model, as sketched in figure 1. Many options have an impact on more than one emission. Furthermore, many actions alter the energy requirements of the facility or subsector to which they are applied.

The total number of individual reduction options (for GHG, NOx, and SOx) is close to 300, described in the Cheminfo and Clearstone reports (Appendix B). They are broken down as follows:

- EPG: 36 existing units, plus 6 announced units, plus 9 generic future units, and a total of 151 abatement options (including 11 fuel switching options)
- Chemicals: 27 facilities, 87 reduction options
- Cement: 3 facilities, 18 options
- Pulp and Paper: 4 facilities, 28 options
- Wood products: 7 facilities, 14 options
- Oil refining: 4 facilities, 7 options
- Conventional oil: one subsector, 18 options
- Gas: one subsector, 57 options
- Oil Sands: one subsector, 25 options

Figure I.1: Representation of reduction options in most sectors (except Upstream Oil and Gas). Each facility is linked to a MARKAL process. Each action is linked to a facility



1.4 Coverage

The MARKAL model has a detailed representation of all sectors of the economy (Industries, EPG, Transportation, Buildings). There are GHG reduction options for all these sectors. For the purpose of this study, additional detailed representations of facilities and of NOx and SOx reduction options have been implemented for the following sectors: EPG (divided in EPG-Coal and EPG-Gas for the purpose of Policy runs), Oil, Gas, Oil Sands, Oil refining, Pulp and Paper, Chemicals, and Cement. These sectors are called the **Covered sectors** in the rest of Appendix A. For the Wood Products sector, only emissions and reduction options are modeled, not the production processes themselves. Therefore, we will not be able to calculate cost or profit changes for that sector.

Note that some portions of these industries emit small quantities of SOx and NOx which are neither modeled nor accounted for in MARKAL (for instance SOx emissions from the Chemicals sector are ignored in MARKAL). The non-modeled NOx and SOx industrial emissions amount to no more than 2% of total industrial emissions.

These 9 sectors will be collectively covered by NOx and SOx emission caps in 2010, 2015, and 2020.

GHG emissions are represented in all sectors, including those not covered by the NOx and SOx caps (i.e. Transportation, Residential, Commercial, and Other Emissions, namely agriculture and landfills). We shall call these the **Uncovered Sectors.** However, it should be remembered that even the sectors not covered by CAC emission caps are equipped with GHG emissions and emission reduction options.

1.5 Optimization of Emission Reductions

In MARKAL, it is possible to apply a combination of emission caps, one per pollutant. Each cap is imposed on covered sectors (and also on uncovered sectors in the case of GHG) via an additional constraint on the Linear program at each period of interest. The model is then run to find a new equilibrium that respects these caps. Since the equilibrium is based on maximizing surplus (profit), the caps are achieved at the minimum cost possible. It is also possible (indeed likely) that in the constrained equilibrium, the outputs of the various sectors will be affected, since the outputs are price elastic, and since the model endogenously recomputes commodity prices taking into account the additional costs of reduction.

The model selects a subset of the many reduction options, in order to achieve the caps at minimum loss of profit. The selection is done using Linear Programming. Traditional cost curve methods are not suited for selecting an optimal subset of options, due to the combinatorially large number of potential subsets of options available to reach the caps.

1.6 Assumptions and Emission Calibration

1.6.1 Technologies, Energy, and Materials

The vast majority of the model's assumptions consist in the very large technological database, containing more than 2000 technologies. The Alberta model used for this project has the same data base as was used for the National Climate Change Process (NCCP) work in 2002 with some recent updates mentioned below. Moreover, the model is calibrated to the most recent assumptions of the NCCP. The following main techno-economic assumptions hold in the Base case:

- The electricity sector has been updated by the inclusion of 6 new announced units: Fording 1 and 2, Genesee 3, Keephills 3 and 4, and AES. The first five units are coal fired and the last is a combined cycle gas turbine unit.

- As already mentioned, facilities have been added in most industries. However, the inclusion of these facilities in the database serves only to account for emissions of SOx and NOx. They modify in no way the technological structure of MARKAL.
- The oil and gas exports are assumed to be price takers. The market prices of these three commodities have been derived from the BASE run of the North American model.
    - Crude oil export price: constant at C$ 34/barrel from 2005 to 2020
    - Exported gas prices (at US border)[1]:
        - 2005: $4.10/GJ
        - 2010: $4.03/GJ
        - 2015: $4.30/GJ
        - 2020: $4.39/GJ
    - Coal prices (sub bituminous):
        - 2005: $0.69/GJ
        - 2010: $0.73/GJ
        - 2015: $0.76/GJ
        - 2020: $0.80/GJ
- The Chemicals, Pulp and Paper, and Cement sectors have a price elasticity of -4.0.
- Discount rate: 10% (in real terms)
- Table 1 indicates the annual growth rates in key industries assumed in the Base case. These rates are compatible with the sectors' economic growth rates assumed in the latest version of the CEOU.
- Tables 2 (oil and gas) and 3 (electricity) indicate the outputs of the main energy forms. These are not assumptions. They are calculated by the model. They are, however, calibrated to the CEOU energy outputs.

Table I.1. Base Case annual growth rates in key industries

	2003-2007	2008-2012	2013-2017	2018-2022
Mining	2.8%	2.0%	2.5%	2.5%
Chemicals	3.0%	2.7%	3.4%	2.8%
Cement	2.2%	1.3%	-0.3%	1.3%
Other manufacturing*	1.0%	0.5%	0.5%	0.5%
Pulp & Paper	1.2%	1.2%	1.1%	1.2%

* Includes all industries not identified explicitly.

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[1] In the Gas price sensitivity (see Part IV or Section 4), gas price was increased to $5.00/GJ throughout the horizon.

Table I.2. Base Case Oil and Gas production

PJ/y	2000	2005	2010	2015	2020
Nat Gas	5695	6959	6785	6774	6730
PJ/y	**2000**	**2005**	**2010**	**2015**	**2020**
Heavy Crude	767	707	659	627	563
Light Crude	1365	1316	1275	1246	1137
Total	**2132**	**2023**	**1934**	**1873**	**1700**
PJ/y	**2000**	**2005**	**2010**	**2015**	**2020**
In Situ Bitumen	583	1265	2069	2189	2189
Mined Bitumen	863	1633	2364	2616	2616
Total Bitumen	**1446**	**2898**	**4433**	**4805**	**4805**

Table I.3. Base Case Electricity generation

TWh/yr	2000	2005	2010	2015	2020
Coal	44.1	46.5	55.6	59	58.6
Gas	12.5	19.8	15.4	16.8	19.9
Hydro	2.4	2.4	2.4	2.4	2.4
Wind	0.1	0.1	0.1	0.1	0.1
Biomass	0.4	0	0	0.9	1.4
Total generation	**59.5**	**68.8**	**73.6**	**79.3**	**82.5**

1.6.2 Emissions

1.6.2.1 GHG emissions

The GHG emissions are very close to those calculated for the NCCP, with some minor differences in the upstream oil and gas sector, which have been slightly revised to better mimic the latest assumptions of the National Process. Tables 4, 5, 6, show the GHG emissions by sector from the model, from the Cheminfo report (Appendix C), and from the adjusted CEOU, respectively.

Table I.4. GHG emissions by all sectors in the Base Case (MARKAL model)

Mt CO2e	Sector	2000	2005	2010	2015	2020
BASE	Electric power generation	46.3	50.9	57.4	61.1	61.7
	Industrial	25.8	26.4	28.8	33.2	36.2
	Upstream O&G	68.8	92.5	108.1	115.4	114.2
	Residential	7.1	6.7	6.3	5.9	6.2
	Commercial	5.5	5.4	5.0	4.7	5.0
	Transports	24.9	26.6	27.7	29.5	32.0
	Landfills	1.0	1.0	1.0	1.0	1.0
	Other	18.0	18.6	20.3	20.3	21.3
	TOTAL GHG	198	228	255	271	278

Table I.5. GHG emissions by all sectors in the Base Case (Cheminfo report, Appendix C)

GHG emissions	Cheminfo Report				
units: Mt CO2e	2000	2005	2010	2015	2020
Electric power generation	51	53	57	57	58
Industries except EPG	30	28	30	35	39
Residential heating	8	7	6	6	6
Commercial/institutional	5	5	5	5	5
Fossil fuel industries (oil, gas, oil refining	78	104	118	123	120
Transportation	31	27	28	29	32
Agricultural: soils, manure, livestock	19	18	19	19	20
Waste, HFC, Miscellaneous	1	1	1	1	1
Total GHG Emissions	**223**	**242**	**264**	**275**	**280**

Table I.6. GHG emissions by all sectors in the Base Case (CEOU adjusted Feb 2002)

GHG emissions	CEOU adjusted Projection				
units: Mt CO2e	2000	2005	2010	2015	2020
POWER GENERATION	47	52.4	56.3	60.3	61.8
TOTAL INDUSTRIAL	27	29	31	32	34
RESIDENTIAL AND AGRICULTURE	8	8	8	8	8
COMMERCIAL & PUBLIC ADMIN	6	6	5	5	5
FOSSIL FUEL INDUSTRIES	68	91.8	100.9	104.8	103.8
TRANSPORTATION	29	33	35	38	41
AGROECOSYSTEMS	18	19	20	20	21
WASTE	1	1	1	1	1
HFC	0	0	1	1	1
GHG Alberta	**204**	**240**	**258**	**270**	**277**

Table I.2. Base Case Oil and Gas production

PJ/y	2000	2005	2010	2015	2020
Nat Gas	5695	6959	6785	6774	6730
PJ/y	**2000**	**2005**	**2010**	**2015**	**2020**
Heavy Crude	767	707	659	627	563
Light Crude	1365	1316	1275	1246	1137
Total	**2132**	**2023**	**1934**	**1873**	**1700**
PJ/y	**2000**	**2005**	**2010**	**2015**	**2020**
In Situ Bitumen	583	1265	2069	2189	2189
Mined Bitumen	863	1633	2364	2616	2616
Total Bitumen	**1446**	**2898**	**4433**	**4805**	**4805**

Table I.3. Base Case Electricity generation

TWh/yr	2000	2005	2010	2015	2020
Coal	44.1	46.5	55.6	59	58.6
Gas	12.5	19.8	15.4	16.8	19.9
Hydro	2.4	2.4	2.4	2.4	2.4
Wind	0.1	0.1	0.1	0.1	0.1
Biomass	0.4	0	0	0.9	1.4
Total generation	**59.5**	**68.8**	**73.6**	**79.3**	**82.5**

1.6.2 Emissions

1.6.2.1 GHG emissions

The GHG emissions are very close to those calculated for the NCCP, with some minor differences in the upstream oil and gas sector, which have been slightly revised to better mimic the latest assumptions of the National Process. Tables 4, 5, 6, show the GHG emissions by sector from the model, from the Cheminfo report (Appendix C), and from the adjusted CEOU, respectively.

Table I.4. GHG emissions by all sectors in the Base Case (MARKAL model)

Mt CO2e	Sector	2000	2005	2010	2015	2020
BASE	Electric power generation	46.3	50.9	57.4	61.1	61.7
	Industrial	25.8	26.4	28.8	33.2	36.2
	Upstream O&G	68.8	92.5	108.1	115.4	114.2
	Residential	7.1	6.7	6.3	5.9	6.2
	Commercial	5.5	5.4	5.0	4.7	5.0
	Transports	24.9	26.6	27.7	29.5	32.0
	Landfills	1.0	1.0	1.0	1.0	1.0
	Other	18.0	18.6	20.3	20.3	21.3
	TOTAL GHG	198	228	255	271	278

Table I.5. GHG emissions by all sectors in the Base Case (Cheminfo report, Appendix C)

GHG emissions	Cheminfo Report				
units: Mt CO2e	2000	2005	2010	2015	2020
Electric power generation	51	53	57	57	58
Industries except EPG	30	28	30	35	39
Residential heating	8	7	6	6	6
Commercial/institutional	5	5	5	5	5
Fossil fuel industries (oil, gas, oil refining	78	104	118	123	120
Transportation	31	27	28	29	32
Agricultural: soils, manure, livestock	19	18	19	19	20
Waste, HFC, Miscellaneous	1	1	1	1	1
Total GHG Emissions	223	242	264	275	280

Table I.6. GHG emissions by all sectors in the Base Case (CEOU adjusted Feb 2002)

GHG emissions	CEOU adjusted Projection				
units: Mt CO2e	2000	2005	2010	2015	2020
POWER GENERATION	47	52.4	56.3	60.3	61.8
TOTAL INDUSTRIAL	27	29	31	32	34
RESIDENTIAL AND AGRICULTURE	8	8	8	8	8
COMMERCIAL & PUBLIC ADMIN	6	6	5	5	5
FOSSIL FUEL INDUSTRIES	68	91.8	100.9	104.8	103.8
TRANSPORTATION	29	33	35	38	41
AGROECOSYSTEMS	18	19	20	20	21
WASTE	1	1	1	1	1
HFC	0	0	1	1	1
GHG Alberta	204	240	258	270	277

Commentary

- Total GHG emissions in MARKAL are close to those in the adjusted CEOU. This is also true in each sector with two exceptions: Upstream and Transportation. Note that MARKAL has a tendency to underestimate transportation emissions, due to its slightly more optimistic assumptions concerning efficiency improvements in that sector.
- Some differences between MARKAL and Cheminfo emissions occur in three sectors:
  - In Oil Sands, MARKAL (following the CEOU forecast) assumes less extraction capacity than Cheminfo, especially in the later periods.
  - In Chemicals, the difference is due to small non-covered operations, and to area emissions, which are also not covered in MARKAL.
  - In the EPG sector, the difference is due solely to the fact that MARKAL produces less electricity than assumed in Cheminfo, especially starting in 2010. MARKAL is closely calibrated to the CEOU in that sector as well.

1.6.2.2 CAC emissions

The emission factors for NOx and SOx (which were not present in the NCCP data), have been added to the model using the detailed data provided by Cheminfo as part of this project. Tables 7 to 10 exhibit the base case emissions from MARKAL and from the Cheminfo report.

Table I.7. NOx emissions by covered industries in the Base Case (MARKAL model)

NOx emissions	MARKAL Base Case				
units: kt	2000	2005	2010	2015	2020
EPG	88.4	94.2	97.5	99.7	100.3
Oil Sands	54.0	105.3	156.7	170.3	170.3
Conventional O&G	315.9	375.4	371.9	377.2	378.6
Oil refining	4.7	4.4	4.5	5.5	5.7
Cement	4.8	5.4	5.7	5.6	6.0
Chemicals	14.4	16.7	19.1	22.6	25.9
Pulp and Paper	3.8	4.0	4.3	4.6	4.8
Wood products	5.2	5.5	5.9	6.3	6.7
TOTAL NOx covered industries	**491.2**	**611.0**	**665.8**	**691.9**	**698.3**

Table I. 8. NOx emissions by covered industries in the Base Case (Cheminfo report)

NOx emissions	Cheminfo Report				
units: kt	2000	2005	2010	2015	2020
EPG	94.0	102.0	113.0	115.0	117.0
Oil Sands	54.0	89.0	159.0	198.0	202.0
Conventional O&G	292.0	324.0	346.0	366.0	378.0
Oil refining	4.6	4.6	4.8	5.0	5.2
Cement	5.0	5.0	4.8	4.9	4.8
Chemicals	24.5	26.9	29.1	32.2	5.2
Pulp and Paper	3.8	4.2	4.8	5.2	5.6
Wood products					
TOTAL NOx industries	**500.0**	**574.0**	**682.0**	**746.0**	**769.0**

Notes: Some differences between MARKAL and Cheminfo emissions occur in the same three sectors as for GHG emissions, as for the same reasons:

- In Oil Sands, MARKAL (following the CEOU) assumes less extraction capacity than Cheminfo
- In Chemicals, the difference is due to small non covered operations and to area emissions
- In EPG sector, MARKAL produces less electricity than assumed in Cheminfo, especially starting in 2010.

Table I.9. SOx emissions by covered industries in the Base Case (MARKAL model)

SOx emissions	MARKAL base case				
units: kt	2000	2005	2010	2015	2020
EPG	128.1	126.1	129.3	135.0	135.0
Oil Sands	94.0	116.9	168.7	173.7	164.0
Conventional O&G	260.0	235.8	229.4	228.4	225.2
Oil refining	13.1	12.2	12.4	15.4	15.8
Cement	2.9	3.2	3.4	3.3	3.6
Chemicals	0.0	0.0	0.0	0.0	0.0
Pulp and Paper	2.0	2.2	2.3	2.4	2.6
TOTAL SOx covered industries	**500.0**	**496.4**	**545.6**	**558.2**	**546.2**

Table I.10. SOx emissions by covered industries in the Base Case (Cheminfo report)

SOx emissions	Cheminfo Report				
units: kt	2000	2005	2010	2015	2020
EPG	125.0	129.0	131.0	131.0	131.0
Oil Sands	94.0	117.0	162.0	164.0	164.0
Conventional O&G	260.0	238.0	230.0	227.0	225.0
Oil refining	9.8	8.6	12.0	12.6	13.2
Cement	2.8	2.7	2.1	2.2	2.1
Chemicals	3.0	3.0	3.0	3.0	3.0
Pulp and Paper	2.0	2.6	2.8	3.0	3.2
TOTAL SOx industries	**503.0**	**508.0**	**551.0**	**551.0**	**551.0**

Commentary

- Total GHG emissions in MARKAL are close to those in the adjusted CEOU. This is also true in each sector with two exceptions: Upstream and Transportation. Note that MARKAL has a tendency to underestimate transportation emissions, due to its slightly more optimistic assumptions concerning efficiency improvements in that sector.
- Some differences between MARKAL and Cheminfo emissions occur in three sectors:
    - In Oil Sands, MARKAL (following the CEOU forecast) assumes less extraction capacity than Cheminfo, especially in the later periods.
    - In Chemicals, the difference is due to small non-covered operations, and to area emissions, which are also not covered in MARKAL.
    - In the EPG sector, the difference is due solely to the fact that MARKAL produces less electricity than assumed in Cheminfo, especially starting in 2010. MARKAL is closely calibrated to the CEOU in that sector as well.

1.6.2.2 CAC emissions

The emission factors for NOx and SOx (which were not present in the NCCP data), have been added to the model using the detailed data provided by Cheminfo as part of this project. Tables 7 to 10 exhibit the base case emissions from MARKAL and from the Cheminfo report.

Table I.7. NOx emissions by covered industries in the Base Case (MARKAL model)

NOx emissions	MARKAL Base Case				
units: kt	**2000**	**2005**	**2010**	**2015**	**2020**
EPG	88.4	94.2	97.5	99.7	100.3
Oil Sands	54.0	105.3	156.7	170.3	170.3
Conventional O&G	315.9	375.4	371.9	377.2	378.6
Oil refining	4.7	4.4	4.5	5.5	5.7
Cement	4.8	5.4	5.7	5.6	6.0
Chemicals	14.4	16.7	19.1	22.6	25.9
Pulp and Paper	3.8	4.0	4.3	4.6	4.8
Wood products	5.2	5.5	5.9	6.3	6.7
TOTAL NOx covered industries	**491.2**	**611.0**	**665.8**	**691.9**	**698.3**

Table I. 8. NOx emissions by covered industries in the Base Case (Cheminfo report)

NOx emissions	Cheminfo Report				
units: kt	2000	2005	2010	2015	2020
EPG	94.0	102.0	113.0	115.0	117.0
Oil Sands	54.0	89.0	159.0	198.0	202.0
Conventional O&G	292.0	324.0	346.0	366.0	378.0
Oil refining	4.6	4.6	4.8	5.0	5.2
Cement	5.0	5.0	4.8	4.9	4.8
Chemicals	24.5	26.9	29.1	32.2	35.2
Pulp and Paper	3.8	4.2	4.8	5.2	5.6
Wood products					
TOTAL NOx industries	**500.0**	**574.0**	**682.0**	**746.0**	**769.0**

Notes: Some differences between MARKAL and Cheminfo emissions occur in the same three sectors as for GHG emissions, as for the same reasons:

- In Oil Sands, MARKAL (following the CEOU) assumes less extraction capacity than Cheminfo
- In Chemicals, the difference is due to small non covered operations and to area emissions
- In EPG sector, MARKAL produces less electricity than assumed in Cheminfo, especially starting in 2010.

Table I.9. SOx emissions by covered industries in the Base Case (MARKAL model)

SOx emissions	MARKAL base case				
units: kt	2000	2005	2010	2015	2020
EPG	128.1	126.1	129.3	135.0	135.0
Oil Sands	94.0	116.9	168.7	173.7	164.0
Conventional O&G	260.0	235.8	229.4	228.4	225.2
Oil refining	13.1	12.2	12.4	15.4	15.8
Cement	2.9	3.2	3.4	3.3	3.6
Chemicals	0.0	0.0	0.0	0.0	0.0
Pulp and Paper	2.0	2.2	2.3	2.4	2.6
TOTAL SOx covered industries	**500.0**	**496.4**	**545.6**	**558.2**	**546.2**

Table I.10. SOx emissions by covered industries in the Base Case (Cheminfo report)

SOx emissions	Cheminfo Report				
units: kt	2000	2005	2010	2015	2020
EPG	125.0	129.0	131.0	131.0	131.0
Oil Sands	94.0	117.0	162.0	164.0	164.0
Conventional O&G	260.0	238.0	230.0	227.0	225.0
Oil refining	9.8	8.6	12.0	12.6	13.2
Cement	2.8	2.7	2.1	2.2	2.1
Chemicals	3.0	3.0	3.0	3.0	3.0
Pulp and Paper	2.0	2.6	2.8	3.0	3.2
TOTAL SOx industries	**503.0**	**508.0**	**551.0**	**551.0**	**551.0**

1.6.2.3 Mercury emissions

Mercury emissions have been introduced in the model in the EPG sector (coal plants), from data provided by Cheminfo on a unit per unit basis. Table 1. 11 shows the total Mercury emissions from these sources.

Table I. 11. Mercury emissions from EPG sector in the Base case (MARKAL and Cheminfo)

Kg/yr	**2000**	**2005**	**2010**	**2015**	**2020**
Cheminfo (approximate)	700	800	900	900	900
MARKAL	744	789	940	1002	1002

Commentary

- In the EPG, in spite of producing less energy, MARKAL emits more Mercury and more SOx (especially in the latter years) because the model implements more coal-based generation (and less gas) than assumed in the Cheminfo report. Again, MARKAL is closely conforming to the CEOU assumptions (although the model did not have to be coaxed into mimicking the CEOU).

2. Five Exploratory Cases

2.1 Description of the 5 Exploratory Cases

The main purpose of the five Exploratory Cases was to test the model and develop a better understanding on the cost of reductions for various combinations of reduction targets. One of the four sets of targets was subsequently selected for the more detailed study of the various permit trading options (Cases 4a, 6, 7, 8).

Side-by-side results are presented for the five cases: the Base case, and four emission constrained runs with various combinations of emission constraints on GHG, NOx, SOx, and Mercury. The following general assumptions are made for all constrained runs:

- All caps start in 2010 and extend until the end of the horizon, namely 2020. Since MARKAL operates with 5-year periods, this means that the caps are effectively applied from 2008 to 2022.
- GHG caps: in all four constrained cases 2 to 5, the industrial sectors' GHG emissions are collectively capped separately from the uncovered sectors (Transportation, Residential, Commercial, Agriculture and Landfills), which receive a collective cap of their own. Table II-1 shows the values of the caps for the covered and uncovered blocks. In addition, it is assumed that the covered sectors have access to a backstop reduction option (also called price cap[2]) costing $9.2, $12, and $14.7 per tonne of CO2e, at periods 2010, 2015, and 2020 respectively. Therefore, the shadow prices of GHG in the covered sectors may never exceed these values. These assumptions allow free GHG trading between and within the covered sectors. They also allow free trading between and within the uncovered sectors. But the covered and uncovered "bubbles" are not allowed to trade between themselves.
- NOx and SOx caps (if any) are applied globally to the 9 covered industrial sectors (emissions and emission reductions from Mining and from Other Manufacturing are not modeled). See table II.1 for the values of the NOx and SOx caps in each constrained run. A collective cap on all industrial sectors means that these sectors are allowed to equalize their marginal reduction costs, i.e. to implicitly trade their emission reductions, within each covered sector, and across covered sectors.
- In runs 2 to 5, there are as many mercury caps as there are coal-fired power generating units (present and future). Each unit's emissions are capped at 50% of their value in the Base case, at each period: 2010, 2015, and 2020. This implies that there is no trading of mercury emissions between units. Finally, a backstop

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[2] The backstop option may be interpreted in either of two ways:

a) as a possibility to buy permits from an external market at the indicated prices, or

b) as a backstop technology that eliminates CO_2 / GHG emissions at the indicated costs.

In the text we shall freely use wording compatible to either of these interpretations reduction option at $92,700/Kg of Hg for all periods is applied, based on Alberta Environment input.

- In these runs, no consideration is given to the trading of permits. In other words, it is implicitly assumed that each sector is allocated gratis exactly the number of permits required to emit at the optimal level prescribed by the model's optimal solution. Hence there is no need to trade permits.

Case 1: Base case (no constraint on emissions)

Case 2: GHG and mercury emissions are capped as per Table II.1 (See section 3.4 in the *Preliminary Analysis and Discussion Document*). NOx and SOx are not constrained

Case 3: Same as Case 2, but NOx emissions in 2020 are capped at 115% of the emissions in period 2000, base case, and SOx emissions are capped in 2020 at the Base case level in period 2000. It is applied as a single cap on all covered sectors collectively Emissions of NOx and SOx in 2010 and 2015 are capped at levels that insure that reductions in these periods are linearly interpolated between 0 (in 2005) and the reductions in 2020. See Table II.1 and section 3.4 the *Preliminary Analysis and Discussion Document* for details.

Case 4: Same as Case 3, but the NOx cap in 2020 is equal to 100% of the 2000 base emissions, and the SOx cap in 2020 is equal to 70% of the 2000 Base emissions.

Case 5: same as Cases 3 and 4, but the NOx cap in 2020 is equal to 85% of the 2000 base emissions, and the SOx cap in 2020 is equal to 40 % of the 2000 Base emissions.

Table II.1: Emission targets for the five exploratory cases

	Units	2000	2005	2010	2015	2020
NOx Base Case Emissions	tonnes	491216	610994	665751	691901	698348
NOx Low reduction case target Case 3	tonnes	free	free	621268	602935	564899
NOx Med reduction Case target Case 4	tonnes	free	free	596707	553813	491216
NOx high reduction case target Case 5	tonnes	free	free	572146	504692	417534
SOx Base Case Emissions	tonnes	500046	496360	545589	558160	546201
SOx Low reduction case target Case 3	tonnes	free	free	530203	527389	500046
SOx Med reduction case target Case 4	tonnes	free	free	480199	427380	350032
SOx high reduction case target Case 5	tonnes	free	free	430194	327371	200018
GHG (Covered) Base Case	Mtonnes	141	170	194	209	212
GHG covered –all constrained cases	Mtonnes	free	free	178	179	158
GHG (non covered) Base Case	Mtonnes	57	58	60	61	66
GHG non covered – all constrained cases	Mtonnes	free	free	56	56	60
Mercury Base Case emissions	Kg	744	789	935	1002	1002
Mercury – all constrained cases *	Kg	free	free	458	501	501
*** Note that separate Mercury caps are imposed individually on each generating unit (no trading)**						

2.2 Summary Results

Table II.2 is a summary of the results obtained for the five cases. It contains the overall loss of surplus (labeled Total Cost), followed by the amounts of cumulative reductions of the four pollutants affected in Alberta from periods 2010 to 2020. The right most portion of the table shows the marginal costs of reduction (shadow prices) of the three pollutants at the three periods of interest.

Table II.2: Summary of main results for the five cases

	Total Cost	Cumulative emission reductions					Marginal cost of emission reductions				
		GHGs	NOx	SOx	Hg	period	GHGs Uncovered	GHG covered	NOx	SOx	Hg
	$million	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	$/t NOx	$/t SOx	$/kg
Case 2	50	490	362	1112	8925	**2010**	0	9	–	–	Depends on facility.
						2015	30	12	–	–	
						2020	41	15	–	–	
Case 3	61	490	1334	1115	8925	**2010**	0	9	61	0	Generally equal to backstop price, with a few exceptions.
						2015	30	12	61	0	
						2020	42	15	61	0	
Case 4	110	505	2071	1962	8985	**2010**	0	9	61	17	
						2015	32	12	61	218	
						2020	39	15	1141	218	
Case 5	349	520	2808	3462	9125	**2010**	0	9	61	218	
						2015	37	12	354	415	
						2020	32	15	1141	1795	

Notes:

- **The total cost is the net present value in 2000 of costs incurred over the period 2005 through 2020 discounted at 10% per year. The monetary unit is 1995 Canadian dollars.**
- **Cumulative emission reduction is calculated as the sum of the annual reductions from Base case emissions for 2010, 2015, and 2020 multiplied by 5.**
- **The marginal cost of GHG emission reduction is different for covered and for non covered sectors**
- **The marginal cost of Mercury emission reduction is specific to each unit (separate caps). However, in most cases, the marginal cost is that of the backstop option**

Commentary

- The overall loss of surplus (cost) is relatively modest, even in the most severe reduction case. However, note that the costs are presented as present values in year 2000, whereas most costs are of course incurred in 2010, 2015, and 2020. Therefore, the net present value (NPV) tends to give an attenuated picture of the stream of costs. Note also that costs are not evenly spread across sectors. In section 4, we present a time-dependent and sector specific picture of the profits.

reduction option at $92,700/Kg of Hg for all periods is applied, based on Alberta Environment input.

- In these runs, no consideration is given to the trading of permits. In other words, it is implicitly assumed that each sector is allocated gratis exactly the number of permits required to emit at the optimal level prescribed by the model's optimal solution. Hence there is no need to trade permits.

Case 1: Base case (no constraint on emissions)

Case 2: GHG and mercury emissions are capped as per Table II.1 (See section 3.4 in the *Preliminary Analysis and Discussion Document*). NOx and SOx are not constrained

Case 3: Same as Case 2, but NOx emissions in 2020 are capped at 115% of the emissions in period 2000, base case, and SOx emissions are capped in 2020 at the Base case level in period 2000. It is applied as a single cap on all covered sectors collectively Emissions of NOx and SOx in 2010 and 2015 are capped at levels that insure that reductions in these periods are linearly interpolated between 0 (in 2005) and the reductions in 2020. See Table II.1 and section 3.4 the *Preliminary Analysis and Discussion Document* for details.

Case 4: Same as Case 3, but the NOx cap in 2020 is equal to 100% of the 2000 base emissions, and the SOx cap in 2020 is equal to 70% of the 2000 Base emissions.

Case 5: same as Cases 3 and 4, but the NOx cap in 2020 is equal to 85% of the 2000 base emissions, and the SOx cap in 2020 is equal to 40 % of the 2000 Base emissions.

Table II.1: Emission targets for the five exploratory cases

	Units	2000	2005	2010	2015	2020
NOx Base Case Emissions	tonnes	491216	610994	665751	691901	698348
NOx Low reduction case target Case 3	tonnes	free	free	621268	602935	564899
NOx Med reduction Case target Case 4	tonnes	free	free	596707	553813	491216
NOx high reduction case target Case 5	tonnes	free	free	572146	504692	417534
SOx Base Case Emissions	tonnes	500046	496360	545589	558160	546201
SOx Low reduction case target Case 3	tonnes	free	free	530203	527389	500046
SOx Med reduction case target Case 4	tonnes	free	free	480199	427380	350032
SOx high reduction case target Case 5	tonnes	free	free	430194	327371	200018
GHG (Covered) Base Case	Mtonnes	141	170	194	209	212
GHG covered –all constrained cases	Mtonnes	free	free	178	179	158
GHG (non covered) Base Case	Mtonnes	57	58	60	61	66
GHG non covered – all constrained cases	Mtonnes	free	free	56	56	60
Mercury Base Case emissions	Kg	744	789	935	1002	1002
Mercury – all constrained cases *	Kg	free	free	458	501	501

* Note that separate Mercury caps are imposed individually on each generating unit (no trading)

2.2 Summary Results

Table II.2 is a summary of the results obtained for the five cases. It contains the overall loss of surplus (labeled Total Cost), followed by the amounts of cumulative reductions of the four pollutants affected in Alberta from periods 2010 to 2020. The right most portion of the table shows the marginal costs of reduction (shadow prices) of the three pollutants at the three periods of interest.

Table II.2: Summary of main results for the five cases

	Total Cost	Cumulative emission reductions					Marginal cost of emission reductions				
		GHGs	NOx	SOx	Hg	period	GHGs Uncovered	GHG covered	NOx	SOx	Hg
	$million	MtCO$_2$e	kt NO$_2$	kt SO$_2$	kg		\$/tCO$_2$e	\$/tCO$_2$e	\$/t NO$_2$	\$/t SO$_2$	$/kg
Case 2	50	490	362	1112	8925	**2010**	0	9	–	–	Depends on facility.
						2015	30	12	–	–	
						2020	41	15	–	–	
Case 3	61	490	1334	1115	8925	**2010**	0	9	61	0	Generally equal to backstop price, with a few exceptions.
						2015	30	12	61	0	
						2020	42	15	61	0	
Case 4	110	505	2071	1962	8985	**2010**	0	9	61	17	
						2015	32	12	61	218	
						2020	39	15	1141	218	
Case 5	349	520	2808	3462	9125	**2010**	0	9	61	218	
						2015	37	12	354	415	
						2020	32	15	1141	1795	

Notes:

- **The total cost is the net present value in 2000 of costs incurred over the period 2005 through 2020 discounted at 10% per year. The monetary unit is 1995 Canadian dollars.**
- **Cumulative emission reduction is calculated as the sum of the annual reductions from Base case emissions for 2010, 2015, and 2020 multiplied by 5.**
- **The marginal cost of GHG emission reduction is different for covered and for non covered sectors**
- **The marginal cost of Mercury emission reduction is specific to each unit (separate caps). However, in most cases, the marginal cost is that of the backstop option**

Commentary

- The overall loss of surplus (cost) is relatively modest, even in the most severe reduction case. However, note that the costs are presented as present values in year 2000, whereas most costs are of course incurred in 2010, 2015, and 2020. Therefore, the net present value (NPV) tends to give an attenuated picture of the stream of costs. Note also that costs are not evenly spread across sectors. In section 4, we present a time-dependent and sector specific picture of the profits.

- Case 2 has a small cost but achieves significant ancillary reductions of SOx, plus some reductions of NOx

- The converse is not true: imposing even the most severe CAC constraints in Case 5, does not induce significant additional GHG or mercury emission reductions.

- Case 3 achieves significant reductions of NOx over case 2 at very little additional cost, but does not abate more SOx than Case 2.

- Each of cases 3, 4, 5, achieves progressively more NOx reductions. In contrast, for SOx, only cases 4 and 5 are significant since in case 3, emissions fall below the set targets of constant SOx emissions (and the shadow price is thus equal to 0).

- The shadow prices of NOx-SOx confirm the above discussion: very low for case 3 (indeed 0 for SOx), and getting larger in Cases 4 and 5.

- The GHG shadow prices of the covered sectors in 2010, 2015, and 2020, are of course simply equal to the prices of the backstop option at these three periods. In contrast, the shadow prices for the non-covered sectors are endogenous, and higher than the backstop option's prices. This should not be a matter for concern, since the non-covered sectors' targets are somewhat arbitrary (although set at reasonable levels), and since even a small change in the target levels could change these shadow prices significantly without disturbing much the overall costs.

2.3 Total Emissions and Reductions

Commentary

- Tables II.3 and II.4 show how total emissions and reductions of each pollutant evolve over time, for all covered sectors together.
- The GHG reductions shown below concern only the reductions physically performed in Alberta. In addition, some GHG permits are sold or purchased (Mt/yr) from the backstop option, as shown in table II.5. Alberta first sells some permits (3 to 4 Mt/year) in the 2010 period, then buys a small amount in 2016, and a more substantial amount in 2020 (15 to 18 Mt/year)

*Table II.3: Emission profiles**

Emissions

GHG Mt	2000	2005	2010	2015	2020
Case 1	197	228	255	271	278
Case 2	197	223	230	238	236
Case 3	197	223	230	238	236
Case 4	197	223	230	238	234
Case 5	197	223	230	236	233
Mercury kg	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	744	789	940	1002	1002
Case 2	744	767	389	386	386
Case 3	744	767	389	386	386
Case 4	744	767	389	386	374
Case 5	744	762	383	368	368
NOx kt	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	491	611	666	692	698
Case 2	491	607	647	667	670
Case 3	491	607	621	603	565
Case 4	491	607	597	554	491
Case 5	491	607	572	505	418
SOx kt	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	500	496	546	558	546
Case 2	500	493	483	479	466
Case 3	500	493	483	478	466
Case 4	500	493	480	427	350
Case 5	500	493	430	327	200

* Emissions of NOx, SOx from covered sectors; emissions of Hg from coal fired Power plants, GHG emissions from all sectors

*Table II.3: Emission profiles**

Emissions

GHG Mt	2000	2005	2010	2015	2020
Case 1	197	228	255	271	278
Case 2	197	223	230	238	236
Case 3	197	223	230	238	236
Case 4	197	223	230	238	234
Case 5	197	223	230	236	233
Mercury kg	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	744	789	940	1002	1002
Case 2	744	767	389	386	386
Case 3	744	767	389	386	386
Case 4	744	767	389	386	374
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Case 4	500	493	480	427	350
Case 5	500	493	430	327	200

* Emissions of NOx, SOx from covered sectors; emissions of Hg from coal fired Power plants, GHG emissions from all sectors

Table II.4: Reductions with respect to Base emissions

	Reductions wrt Base					Reductions wrt Base (%)				
GHG Mt	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-5	-25	-33	-42	0%	-2%	-10%	-12%	-15%
Case 3	0	-5	-25	-33	-42	0%	-2%	-10%	-12%	-15%
Case 4	0	-5	-25	-33	-44	0%	-2%	-10%	-12%	-16%
Case 5	0	-5	-25	-35	-45	0%	-2%	-10%	-13%	-16%
Mercury kg	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-22	-551	-616	-616	0%	-3%	-59%	-61%	-61%
Case 3	0	-22	-551	-616	-616	0%	-3%	-59%	-61%	-61%
Case 4	0	-22	-551	-616	-628	0%	-3%	-59%	-61%	-63%
Case 5	0	-27	-557	-634	-634	0%	-3%	-59%	-63%	-63%
NOx kt	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-4	-18	-25	-28	0%	-1%	-3%	-4%	-4%
Case 3	0	-4	-44	-89	-133	0%	-1%	-7%	-13%	-19%
Case 4	0	-4	-69	-138	-207	0%	-1%	-10%	-20%	-30%
Case 5	0	-4	-94	-187	-281	0%	-1%	-14%	-27%	-40%
SOx kt	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-3	-63	-79	-80	0%	-1%	-12%	-14%	-15%
Case 3	0	-3	-63	-80	-80	0%	-1%	-12%	-14%	-15%
Case 4	0	-3	-65	-131	-196	0%	-1%	-12%	-23%	-36%
Case 5	0	-3	-115	-231	-346	0%	-1%	-21%	-41%	-63%

Table II.5: GHG permits purchased (sold) from the backstop source

GHG Permits purchased Mt/yr	2010	2015	2020
2-GHG-Hg	(3.45)	2.27	18.98
3-LOW RED	(3.45)	2.19	18.98
4-MED RED	(3.51)	2.09	16.71
5-HIGH RED	(3.91)	0.33	15.15

2.4 Sector Emissions

A series of tables are provided showing the emissions, reductions, and percentage reductions of each pollutant. For GHG emissions, the results are first shown by sector (tables II.6, II.7. II.8), and then by subsector (tables II.9, II.10). Tables II.11 to II.13 concern NOx emissions and reductions, and tables II.14 to II.16 concern SOx emissions and reductions.

Commentary on GHG Reductions

Table II.4: Reductions with respect to Base emissions

	Reductions wrt Base					Reductions wrt Base (%)				
GHG Mt	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-5	-25	-33	-42	0%	-2%	-10%	-12%	-15%
Case 3	0	-5	-25	-33	-42	0%	-2%	-10%	-12%	-15%
Case 4	0	-5	-25	-33	-44	0%	-2%	-10%	-12%	-16%
Case 5	0	-5	-25	-35	-45	0%	-2%	-10%	-13%	-16%
Mercury kg	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-22	-551	-616	-616	0%	-3%	-59%	-61%	-61%
Case 3	0	-22	-551	-616	-616	0%	-3%	-59%	-61%	-61%
Case 4	0	-22	-551	-616	-628	0%	-3%	-59%	-61%	-63%
Case 5	0	-27	-557	-634	-634	0%	-3%	-59%	-63%	-63%
NOx kt	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-4	-18	-25	-28	0%	-1%	-3%	-4%	-4%
Case 3	0	-4	-44	-89	-133	0%	-1%	-7%	-13%	-19%
Case 4	0	-4	-69	-138	-207	0%	-1%	-10%	-20%	-30%
Case 5	0	-4	-94	-187	-281	0%	-1%	-14%	-27%	-40%
SOx kt	**2000**	**2005**	**2010**	**2015**	**2020**	**2000**	**2005**	**2010**	**2015**	**2020**
Case 1	0	0	0	0	0	0%	0%	0%	0%	0%
Case 2	0	-3	-63	-79	-80	0%	-1%	-12%	-14%	-15%
Case 3	0	-3	-63	-80	-80	0%	-1%	-12%	-14%	-15%
Case 4	0	-3	-65	-131	-196	0%	-1%	-12%	-23%	-36%
Case 5	0	-3	-115	-231	-346	0%	-1%	-21%	-41%	-63%

Table II.5: GHG permits purchased (sold) from the backstop source

GHG Permits purchased Mt/yr	2010	2015	2020
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2.4 Sector Emissions

A series of tables are provided showing the emissions, reductions, and percentage reductions of each pollutant. For GHG emissions, the results are first shown by sector (tables II.6, II.7. II.8), and then by subsector (tables II.9, II.10). Tables II.11 to II.13 concern NOx emissions and reductions, and tables II.14 to II.16 concern SOx emissions and reductions.

Commentary on GHG Reductions

- Some sectors reduce more than others. In particular Upstream O&G reduces proportionally less than Industries or EPG. This is directly due to the fast growth of Oil sands production (and, to a lesser extent, of gas production).
- Only EPG continues to reduce emissions significantly beyond Case 2. The other sectors have almost the same emissions in all constrained cases. *This indicates that the imposition of CAC constraints has little effect on GHG emissions.*

Commentary on NOx and SOx Reductions

- Similar to GHG, NOx and NOx, reductions do not occur proportionally to emissions.
- Cement, Chemicals, Pulp and Paper, Gas, and EPG perform above average reductions, and the reductions are progressively larger as the emission constraints become more severe.
- In contrast, Conventional oil performs very little reduction of either pollutant.
- Oil refining performs little NOx reductions but significant SOx reductions in Cases 4 and 5.
- Oil sands perform significant reductions only in Case 5 and in 2020 only.

Commentary on Mercury Emissions

- Overall, total Hg emissions are below the 50% target in 2010, 2015, and 2020. This is because some of the planned future coal plants are no longer being invested in the constrained run, and some existing plants are operated at below their BAU level. This is confirmed in table II showing electricity generation by type.
- Most units adopt the backstop technology for reducing Hg emissions. A few, however, need not do so, because their output is sufficiently reduced by the GHG constraint for their mercury emissions to fall below the 50% constraint.
- We also note that no coal-fired unit adopts the fuel switching option.

Table II.6: Emissions of GHG by sector

GHG Emissions Mt/yr		2000	2005	2010	2015	2020
EPG	1-BASE	46.3	50.9	57.4	61.1	61.7
EPG	2-GHG-Hg	46.2	49.3	47.2	47.8	48.2
EPG	3-LOW RED	46.2	49.3	47.2	47.7	48.2
EPG	4-MED RED	46.2	49.3	47.2	47.7	46.1
EPG	5-HIGH RED	46.3	49.1	47	46	44.5
INDUSTRIES	1-BASE	25.8	26.4	28.8	33.2	36.2
INDUSTRIES	2-GHG-Hg	25.4	25.2	23.8	25.4	26.7
INDUSTRIES	3-LOW RED	25.4	25.2	23.8	25.4	26.7
INDUSTRIES	4-MED RED	25.3	25.1	23.7	25.4	26.7
INDUSTRIES	5-HIGH RED	25.3	25.1	23.7	25.4	26.7
UPSTREAM	1-BASE	68.8	92.5	108.1	115.4	114.2
UPSTREAM	2-GHG-Hg	68.7	92.5	103.4	108.5	102
UPSTREAM	3-LOW RED	68.7	92.5	103.4	108.5	102
UPSTREAM	4-MED RED	68.7	92.5	103.4	108.4	101.9
UPSTREAM	5-HIGH RED	68.7	92.5	103.2	108.4	101.8
UNCOVERED	1-BASE	56.6	58.3	60.2	61.3	65.4
UNCOVERED	2-GHG-Hg	56.6	56.3	56.1	56.3	59.6
UNCOVERED	3-LOW RED	56.6	56.3	56.1	56.3	59.6
UNCOVERED	4-MED RED	56.6	56.3	56.1	56.3	59.6
UNCOVERED	5-HIGH RED	56.6	56.3	56.1	56.3	59.6

Table II.7: GHG reductions relative to Base

GHG reductions Mt/yr		2000	2005	2010	2015	2020
EPG	1-BASE	0	0	0	0	0
EPG	2-GHG-Hg	-0.1	-1.6	-10.2	-13.3	-13.5
EPG	3-LOW RED	-0.1	-1.6	-10.2	-13.4	-13.5
EPG	4-MED RED	-0.1	-1.6	-10.2	-13.4	-15.6
EPG	5-HIGH RED	0	-1.8	-10.4	-15.1	-17.2
INDUSTRIES	1-BASE	0	0	0	0	0
INDUSTRIES	2-GHG-Hg	-0.4	-1.2	-5	-7.8	-9.5
INDUSTRIES	3-LOW RED	-0.4	-1.2	-5	-7.8	-9.5
INDUSTRIES	4-MED RED	-0.5	-1.3	-5.1	-7.8	-9.5
INDUSTRIES	5-HIGH RED	-0.5	-1.3	-5.1	-7.8	-9.5
UPSTREAM	1-BASE	0	0	0	0	0
UPSTREAM	2-GHG-Hg	-0.1	0	-4.7	-6.9	-12.2
UPSTREAM	3-LOW RED	-0.1	0	-4.7	-6.9	-12.2
UPSTREAM	4-MED RED	-0.1	0	-4.7	-7	-12.3
UPSTREAM	5-HIGH RED	-0.1	0	-4.9	-7	-12.4
UNCOVERED	1-BASE	0	0	0	0	0
UNCOVERED	2-GHG-Hg	0	-2	-4.1	-5	-5.8
UNCOVERED	3-LOW RED	0	-2	-4.1	-5	-5.8
UNCOVERED	4-MED RED	0	-2	-4.1	-5	-5.8
UNCOVERED	5-HIGH RED	0	-2	-4.1	-5	-5.8

Table II.8: Percentage reductions of GHG by sector

GHG reductions % over Base		2000	2005	2010	2015	2020
EPG	1-BASE	0%	0%	0%	0%	0%
EPG	2-GHG-Hg	0%	-3%	-18%	-22%	-22%
EPG	3-LOW RED	0%	-3%	-18%	-22%	-22%
EPG	4-MED RED	0%	-3%	-18%	-22%	-25%
EPG	5-HIGH RED	0%	-4%	-18%	-25%	-28%
INDUSTRIES	1-BASE	0%	0%	0%	0%	0%
INDUSTRIES	2-GHG-Hg	-2%	-5%	-17%	-23%	-26%
INDUSTRIES	3-LOW RED	-2%	-5%	-17%	-23%	-26%
INDUSTRIES	4-MED RED	-2%	-5%	-18%	-23%	-26%
INDUSTRIES	5-HIGH RED	-2%	-5%	-18%	-23%	-26%
UPSTREAM	1-BASE	0%	0%	0%	0%	0%
UPSTREAM	2-GHG-Hg	0%	0%	-4%	-6%	-11%
UPSTREAM	3-LOW RED	0%	0%	-4%	-6%	-11%
UPSTREAM	4-MED RED	0%	0%	-4%	-6%	-11%
UPSTREAM	5-HIGH RED	0%	0%	-5%	-6%	-11%
UNCOVERED	1-BASE	0%	0%	0%	0%	0%
UNCOVERED	2-GHG-Hg	0%	-3%	-7%	-8%	-9%
UNCOVERED	3-LOW RED	0%	-3%	-7%	-8%	-9%
UNCOVERED	4-MED RED	0%	-3%	-7%	-8%	-9%
UNCOVERED	5-HIGH RED	0%	-3%	-7%	-8%	-9%

Table II.6: Emissions of GHG by sector

GHG Emissions Mt/yr		2000	2005	2010	2015	2020
EPG	1-BASE	46.3	50.9	57.4	61.1	61.7
EPG	2-GHG-Hg	46.2	49.3	47.2	47.8	48.2
EPG	3-LOW RED	46.2	49.3	47.2	47.7	48.2
EPG	4-MED RED	46.2	49.3	47.2	47.7	46.1
EPG	5-HIGH RED	46.3	49.1	47	46	44.5
INDUSTRIES	1-BASE	25.8	26.4	28.8	33.2	36.2
INDUSTRIES	2-GHG-Hg	25.4	25.2	23.8	25.4	26.7
INDUSTRIES	3-LOW RED	25.4	25.2	23.8	25.4	26.7
INDUSTRIES	4-MED RED	25.3	25.1	23.7	25.4	26.7
INDUSTRIES	5-HIGH RED	25.3	25.1	23.7	25.4	26.7
UPSTREAM	1-BASE	68.8	92.5	108.1	115.4	114.2
UPSTREAM	2-GHG-Hg	68.7	92.5	103.4	108.5	102
UPSTREAM	3-LOW RED	68.7	92.5	103.4	108.5	102
UPSTREAM	4-MED RED	68.7	92.5	103.4	108.4	101.9
UPSTREAM	5-HIGH RED	68.7	92.5	103.2	108.4	101.8
UNCOVERED	1-BASE	56.6	58.3	60.2	61.3	65.4
UNCOVERED	2-GHG-Hg	56.6	56.3	56.1	56.3	59.6
UNCOVERED	3-LOW RED	56.6	56.3	56.1	56.3	59.6
UNCOVERED	4-MED RED	56.6	56.3	56.1	56.3	59.6
UNCOVERED	5-HIGH RED	56.6	56.3	56.1	56.3	59.6

Table II.7: GHG reductions relative to Base

GHG reductions Mt/yr		2000	2005	2010	2015	2020
EPG	1-BASE	0	0	0	0	0
EPG	2-GHG-Hg	-0.1	-1.6	-10.2	-13.3	-13.5
EPG	3-LOW RED	-0.1	-1.6	-10.2	-13.4	-13.5
EPG	4-MED RED	-0.1	-1.6	-10.2	-13.4	-15.6
EPG	5-HIGH RED	0	-1.8	-10.4	-15.1	-17.2
INDUSTRIES	1-BASE	0	0	0	0	0
INDUSTRIES	2-GHG-Hg	-0.4	-1.2	-5	-7.8	-9.5
INDUSTRIES	3-LOW RED	-0.4	-1.2	-5	-7.8	-9.5
INDUSTRIES	4-MED RED	-0.5	-1.3	-5.1	-7.8	-9.5
INDUSTRIES	5-HIGH RED	-0.5	-1.3	-5.1	-7.8	-9.5
UPSTREAM	1-BASE	0	0	0	0	0
UPSTREAM	2-GHG-Hg	-0.1	0	-4.7	-6.9	-12.2
UPSTREAM	3-LOW RED	-0.1	0	-4.7	-6.9	-12.2
UPSTREAM	4-MED RED	-0.1	0	-4.7	-7	-12.3
UPSTREAM	5-HIGH RED	-0.1	0	-4.9	-7	-12.4
UNCOVERED	1-BASE	0	0	0	0	0
UNCOVERED	2-GHG-Hg	0	-2	-4.1	-5	-5.8
UNCOVERED	3-LOW RED	0	-2	-4.1	-5	-5.8
UNCOVERED	4-MED RED	0	-2	-4.1	-5	-5.8
UNCOVERED	5-HIGH RED	0	-2	-4.1	-5	-5.8

Table II.8: Percentage reductions of GHG by sector

GHG reductions % over Base		2000	2005	2010	2015	2020
EPG	1-BASE	0%	0%	0%	0%	0%
EPG	2-GHG-Hg	0%	-3%	-18%	-22%	-22%
EPG	3-LOW RED	0%	-3%	-18%	-22%	-22%
EPG	4-MED RED	0%	-3%	-18%	-22%	-25%
EPG	5-HIGH RED	0%	-4%	-18%	-25%	-28%
INDUSTRIES	1-BASE	0%	0%	0%	0%	0%
INDUSTRIES	2-GHG-Hg	-2%	-5%	-17%	-23%	-26%
INDUSTRIES	3-LOW RED	-2%	-5%	-17%	-23%	-26%
INDUSTRIES	4-MED RED	-2%	-5%	-18%	-23%	-26%
INDUSTRIES	5-HIGH RED	-2%	-5%	-18%	-23%	-26%
UPSTREAM	1-BASE	0%	0%	0%	0%	0%
UPSTREAM	2-GHG-Hg	0%	0%	-4%	-6%	-11%
UPSTREAM	3-LOW RED	0%	0%	-4%	-6%	-11%
UPSTREAM	4-MED RED	0%	0%	-4%	-6%	-11%
UPSTREAM	5-HIGH RED	0%	0%	-5%	-6%	-11%
UNCOVERED	1-BASE	0%	0%	0%	0%	0%
UNCOVERED	2-GHG-Hg	0%	-3%	-7%	-8%	-9%
UNCOVERED	3-LOW RED	0%	-3%	-7%	-8%	-9%
UNCOVERED	4-MED RED	0%	-3%	-7%	-8%	-9%
UNCOVERED	5-HIGH RED	0%	-3%	-7%	-8%	-9%

Table II.9. Emissions of GHG by subsection

Emissions of GHG	1-BASE	1-BASE	1-BASE	2-GHG-Hg	2-GHG-Hg	2-GHG-Hg	3-LOW RED	3-LOW RED	3-LOW RED	4-MED RED	4-MED RED	4-MED RED	5-HIGH RED	5-HIGH RED	5-HIGH RED
Mt/year	2000	2010	2020	2000	2010	2020	2000	2010	2020	2000	2010	2020	2000	2010	2020
EPG	46.3	58.4	62.6	46.2	48.2	49.3	46.2	48.2	49.3	46.2	48.2	47.1	46.3	48	45.6
GAS	36.5	41	41.7	36.5	36.5	34.6	36.5	36.5	34.6	36.5	36.5	34.5	36.5	36.3	34.4
CHEMICALS	11.6	13.8	18.4	11.6	10.8	12.1	11.6	10.8	12.1	11.6	10.8	12.1	11.6	10.8	12.1
CEMENT	2.1	2.3	2.5	1.8	1.4	1.2	1.8	1.4	1.2	1.8	1.4	1.2	1.8	1.4	1.2
MINING	0.4	0.5	0.6	0.4	0.4	0.6	0.4	0.4	0.6	0.4	0.4	0.6	0.4	0.4	0.6
PAP	0.6	0.9	1.2	0.5	0.7	0.9	0.5	0.7	0.9	0.5	0.7	0.9	0.5	0.7	0.9
OTHER INDUSTRY	4.7	5.3	5.6	4.6	4.8	5	4.6	4.8	5	4.6	4.8	5	4.5	4.8	5.1
CONV OIL	12	9.9	8.3	12	9.7	8.2	12	9.7	8.2	12	9.7	8.1	12	9.7	8.1
OIL REFINING	6.5	6.1	7.8	6.4	5.6	6.8	6.4	5.6	6.8	6.4	5.6	6.8	6.4	5.6	6.8
OIL SANDS	20.3	57.2	64.2	20.2	57.2	59.2	20.2	57.2	59.2	20.2	57.2	59.2	20.2	57.2	59.2
Total covered	140.9	195.3	213	140.3	175.4	177.9	140.3	175.4	177.9	140.3	175.3	175.7	140.3	174.9	174.1

Table II.10. Percentage reductions of GHG emissions by subsection

GHG reductions relative to BASE	2-GHG-Hg	2-GHG-Hg	2-GHG-Hg	3-LOW RED	3-LOW RED	3-LOW RED	4-MED RED	4-MED RED	4-MED RED	5-HIGH RED	5-HIGH RED	5-HIGH RED
	2000	2010	2020	2000	2010	2020	2000	2010	2020	2000	2010	2020
EPG	0%	-17%	-21%	0%	-17%	-21%	0%	-17%	-25%	0%	-18%	-27%
GAS	0%	-11%	-17%	0%	-11%	-17%	0%	-11%	-17%	0%	-12%	-17%
CHEMICALS	0%	-22%	-34%	0%	-22%	-34%	0%	-22%	-34%	0%	-22%	-34%
CEMENT	0%	-39%	-50%	0%	-39%	-50%	0%	-39%	-50%	0%	-39%	-50%
MINING	0%	-7%	-4%	0%	-7%	-4%	0%	-7%	-4%	0%	-7%	-4%
P&P	0%	-16%	-23%	0%	-16%	-23%	0%	-16%	-23%	0%	-16%	-23%
OTH INDUSTRY	0%	-8%	-11%	0%	-8%	-11%	0%	-9%	-11%	0%	-9%	-10%
CONV OIL	0%	-2%	-2%	0%	-2%	-2%	0%	-2%	-2%	0%	-2%	-2%
OIL REFINING	0%	-10%	-14%	-1%	-10%	-14%	0%	-10%	-14%	0%	-10%	-14%
OIL SANDS	0%	0%	-8%	0%	0%	-8%	0%	0%	-8%	0%	0%	-8%
Total covered	0%	-10%	-16%	0%	-10%	-16%	0%	-10%	-18%	0%	-10%	-18%

Table II.11. Emissions of NOx by sector

NOx emissions kt/y		2000	2005	2010	2015	2020
Chemicals	**1-BASE**	14.4	16.7	19.1	22.6	25.9
Chemicals	**2-GHG-Hg**	14.4	16.7	14.9	15.2	17.0
Chemicals	**3-LOW RED**	14.4	16.7	13.0	13.2	14.8
Chemicals	**4-MED RED**	14.4	16.7	13.0	13.2	12.4
Chemicals	**5-HIGH RED**	14.4	16.7	13.0	12.0	12.4
Cement	**1-BASE**	4.8	5.4	5.7	5.6	6.0
Cement	**2-GHG-Hg**	4.8	4.2	3.6	3.0	3.0
Cement	**3-LOW RED**	4.8	4.2	3.6	3.0	3.0
Cement	**4-MED RED**	4.8	4.2	3.6	3.0	1.8
Cement	**5-HIGH RED**	4.8	4.2	3.6	2.2	1.8
P&P	**1-BASE**	3.8	4.0	4.3	4.5	4.8
P&P	**2-GHG-Hg**	3.8	4.0	3.9	3.6	3.9
P&P	**3-LOW RED**	3.8	4.0	3.9	3.6	3.9
P&P	**4-MED RED**	3.8	4.0	3.9	3.6	3.0
P&P	**5-HIGH RED**	3.8	4.0	3.9	3.6	3.0
EPG	**1-BASE**	88.4	94.2	97.5	99.7	100.3
EPG	**2-GHG-Hg**	88.3	91.4	81.0	80.4	80.8
EPG	**3-LOW RED**	88.3	91.4	70.9	70.0	70.7
EPG	**4-MED RED**	88.3	91.4	72.1	71.3	56.3
EPG	**5-HIGH RED**	88.4	91.1	70.5	57.4	52.8
Gas	**1-BASE**	249.7	315.6	317.7	327.6	336.2
Gas	**2-GHG-Hg**	249.7	315.6	320.3	330.2	338.7
Gas	**3-LOW RED**	249.7	315.6	306.3	279.1	246.1
Gas	**4-MED RED**	249.7	315.6	280.5	228.7	198.1
Gas	**5-HIGH RED**	249.7	315.6	257.6	195.4	198.1
Oil Conventional	**1-BASE**	66.3	59.8	54.2	49.6	42.4
Oil Conventional	**2-GHG-Hg**	66.3	59.8	56.5	51.9	43.9
Oil Conventional	**3-LOW RED**	66.3	59.8	56.5	51.9	43.9
Oil Conventional	**4-MED RED**	66.3	59.8	56.5	51.9	42.0
Oil Conventional	**5-HIGH RED**	66.3	59.8	56.5	51.9	42.6
Oil refining	**1-BASE**	4.7	4.4	4.5	5.5	5.7
Oil refining	**2-GHG-Hg**	4.7	4.4	4.4	5.4	5.6
Oil refining	**3-LOW RED**	4.7	4.4	4.4	5.4	5.6
Oil refining	**4-MED RED**	4.7	4.4	4.4	5.4	5.6
Oil refining	**5-HIGH RED**	4.7	4.4	4.4	5.4	5.6
Oil Sands	**1-BASE**	54.0	105.3	156.7	170.3	170.3
Oil Sands	**2-GHG-Hg**	53.7	105.3	156.7	170.3	170.3
Oil Sands	**3-LOW RED**	53.7	105.3	156.7	170.3	170.3
Oil Sands	**4-MED RED**	53.8	105.3	156.7	170.3	166.4
Oil Sands	**5-HIGH RED**	53.8	105.3	156.7	170.3	95.7
Wood Products	**1-BASE**	5.2	5.5	5.9	6.3	6.7
Wood Products	**2-GHG-Hg**	5.2	5.5	5.9	6.3	6.7
Wood Products	**3-LOW RED**	5.2	5.5	5.9	6.3	6.7
Wood Products	**4-MED RED**	5.2	5.5	5.9	6.3	5.7
Wood Products	**5-HIGH RED**	5.2	5.5	5.9	6.3	5.7

Table II.9. Emissions of GHG by subsection

Emissions of GHG	1-BASE	1-BASE	1-BASE	2-GHG-Hg	2-GHG-Hg	2-GHG-Hg	3-LOW RED	3-LOW RED	3-LOW RED	4-MED RED	4-MED RED	4-MED RED	5-HIGH RED	5-HIGH RED	5-HIGH RED
Mt/year	2000	2010	2020	2000	2010	2020	2000	2010	2020	2000	2010	2020	2000	2010	2020
EPG	46.3	58.4	62.6	46.2	48.2	49.3	46.2	48.2	49.3	46.2	48.2	47.1	46.3	48	45.6
GAS	36.5	41	41.7	36.5	36.5	34.6	36.5	36.5	34.6	36.5	36.5	34.5	36.5	36.3	34.4
CHEMICALS	11.6	13.8	18.4	11.6	10.8	12.1	11.6	10.8	12.1	11.6	10.8	12.1	11.6	10.8	12.1
CEMENT	2.1	2.3	2.5	1.8	1.4	1.2	1.8	1.4	1.2	1.8	1.4	1.2	1.8	1.4	1.2
MINING	0.4	0.5	0.6	0.4	0.4	0.6	0.4	0.4	0.6	0.4	0.4	0.6	0.4	0.4	0.6
PAP	0.6	0.9	1.2	0.5	0.7	0.9	0.5	0.7	0.9	0.5	0.7	0.9	0.5	0.7	0.9
OTHER INDUSTRY	4.7	5.3	5.6	4.6	4.8	5	4.6	4.8	5	4.6	4.8	5	4.5	4.8	5.1
CONV OIL	12	9.9	8.3	12	9.7	8.2	12	9.7	8.2	12	9.7	8.1	12	9.7	8.1
OIL REFINING	6.5	6.1	7.8	6.4	5.6	6.8	6.4	5.6	6.8	6.4	5.6	6.8	6.4	5.6	6.8
OIL SANDS	20.3	57.2	64.2	20.2	57.2	59.2	20.2	57.2	59.2	20.2	57.2	59.2	20.2	57.2	59.2
Total covered	140.9	195.3	213	140.3	175.4	177.9	140.3	175.4	177.9	140.3	175.3	175.7	140.3	174.9	174.1

Table II.10. Percentage reductions of GHG emissions by subsection

GHG reductions relative to BASE	2-GHG-Hg	2-GHG-Hg	2-GHG-Hg	3-LOW RED	3-LOW RED	3-LOW RED	4-MED RED	4-MED RED	4-MED RED	5-HIGH RED	5-HIGH RED	5-HIGH RED
	2000	2010	2020	2000	2010	2020	2000	2010	2020	2000	2010	2020
EPG	0%	-17%	-21%	0%	-17%	-21%	0%	-17%	-25%	0%	-18%	-27%
GAS	0%	-11%	-17%	0%	-11%	-17%	0%	-11%	-17%	0%	-12%	-17%
CHEMICALS	0%	-22%	-34%	0%	-22%	-34%	0%	-22%	-34%	0%	-22%	-34%
CEMENT	0%	-39%	-50%	0%	-39%	-50%	0%	-39%	-50%	0%	-39%	-50%
MINING	0%	-7%	-4%	0%	-7%	-4%	0%	-7%	-4%	0%	-7%	-4%
P&P	0%	-16%	-23%	0%	-16%	-23%	0%	-16%	-23%	0%	-16%	-23%
OTH INDUSTRY	0%	-8%	-11%	0%	-8%	-11%	0%	-9%	-11%	0%	-9%	-10%
CONV OIL	0%	-2%	-2%	0%	-2%	-2%	0%	-2%	-2%	0%	-2%	-2%
OIL REFINING	0%	-10%	-14%	-1%	-10%	-14%	0%	-10%	-14%	0%	-10%	-14%
OIL SANDS	0%	0%	-8%	0%	0%	-8%	0%	0%	-8%	0%	0%	-8%
Total covered	0%	-10%	-16%	0%	-10%	-16%	0%	-10%	-18%	0%	-10%	-18%

Table II.11. Emissions of NOx by sector

NOx emissions kt/y		2000	2005	2010	2015	2020
Chemicals	1-BASE	14.4	16.7	19.1	22.6	25.9
Chemicals	2-GHG-Hg	14.4	16.7	14.9	15.2	17.0
Chemicals	3-LOW RED	14.4	16.7	13.0	13.2	14.8
Chemicals	4-MED RED	14.4	16.7	13.0	13.2	12.4
Chemicals	5-HIGH RED	14.4	16.7	13.0	12.0	12.4
Cement	1-BASE	4.8	5.4	5.7	5.6	6.0
Cement	2-GHG-Hg	4.8	4.2	3.6	3.0	3.0
Cement	3-LOW RED	4.8	4.2	3.6	3.0	3.0
Cement	4-MED RED	4.8	4.2	3.6	3.0	1.8
Cement	5-HIGH RED	4.8	4.2	3.6	2.2	1.8
P&P	1-BASE	3.8	4.0	4.3	4.5	4.8
P&P	2-GHG-Hg	3.8	4.0	3.9	3.6	3.9
P&P	3-LOW RED	3.8	4.0	3.9	3.6	3.9
P&P	4-MED RED	3.8	4.0	3.9	3.6	3.0
P&P	5-HIGH RED	3.8	4.0	3.9	3.6	3.0
EPG	1-BASE	88.4	94.2	97.5	99.7	100.3
EPG	2-GHG-Hg	88.3	91.4	81.0	80.4	80.8
EPG	3-LOW RED	88.3	91.4	70.9	70.0	70.7
EPG	4-MED RED	88.3	91.4	72.1	71.3	56.3
EPG	5-HIGH RED	88.4	91.1	70.5	57.4	52.8
Gas	1-BASE	249.7	315.6	317.7	327.6	336.2
Gas	2-GHG-Hg	249.7	315.6	320.3	330.2	338.7
Gas	3-LOW RED	249.7	315.6	306.3	279.1	246.1
Gas	4-MED RED	249.7	315.6	280.5	228.7	198.1
Gas	5-HIGH RED	249.7	315.6	257.6	195.4	198.1
Oil Conventional	1-BASE	66.3	59.8	54.2	49.6	42.4
Oil Conventional	2-GHG-Hg	66.3	59.8	56.5	51.9	43.9
Oil Conventional	3-LOW RED	66.3	59.8	56.5	51.9	43.9
Oil Conventional	4-MED RED	66.3	59.8	56.5	51.9	42.0
Oil Conventional	5-HIGH RED	66.3	59.8	56.5	51.9	42.6
Oil refining	1-BASE	4.7	4.4	4.5	5.5	5.7
Oil refining	2-GHG-Hg	4.7	4.4	4.4	5.4	5.6
Oil refining	3-LOW RED	4.7	4.4	4.4	5.4	5.6
Oil refining	4-MED RED	4.7	4.4	4.4	5.4	5.6
Oil refining	5-HIGH RED	4.7	4.4	4.4	5.4	5.6
Oil Sands	1-BASE	54.0	105.3	156.7	170.3	170.3
Oil Sands	2-GHG-Hg	53.7	105.3	156.7	170.3	170.3
Oil Sands	3-LOW RED	53.7	105.3	156.7	170.3	170.3
Oil Sands	4-MED RED	53.8	105.3	156.7	170.3	166.4
Oil Sands	5-HIGH RED	53.8	105.3	156.7	170.3	95.7
Wood Products	1-BASE	5.2	5.5	5.9	6.3	6.7
Wood Products	2-GHG-Hg	5.2	5.5	5.9	6.3	6.7
Wood Products	3-LOW RED	5.2	5.5	5.9	6.3	6.7
Wood Products	4-MED RED	5.2	5.5	5.9	6.3	5.7
Wood Products	5-HIGH RED	5.2	5.5	5.9	6.3	5.7

Table II.12. NOx reductions by sector

NOx reductions kt		2000	2005	2010	2015	2020
Chemicals	1-BASE	0.0	0.0	0.0	0.0	0.0
Chemicals	2-GHG-Hg	0.0	0.0	-4.2	-7.4	-8.9
Chemicals	3-LOW RED	0.0	0.0	-6.1	-9.3	-11.1
Chemicals	4-MED RED	0.0	0.0	-6.1	-9.3	-13.5
Chemicals	5-HIGH RED	0.0	0.0	-6.1	-10.5	-13.5
Cement	1-BASE	0.0	0.0	0.0	0.0	0.0
Cement	2-GHG-Hg	0.0	-1.1	-2.1	-2.6	-3.0
Cement	3-LOW RED	0.0	-1.1	-2.1	-2.6	-3.0
Cement	4-MED RED	0.0	-1.1	-2.1	-2.6	-4.3
Cement	5-HIGH RED	0.0	-1.1	-2.1	-3.4	-4.3
P&P	1-BASE	0.0	0.0	0.0	0.0	0.0
P&P	2-GHG-Hg	0.0	0.0	-0.4	-0.9	-1.0
P&P	3-LOW RED	0.0	0.0	-0.4	-0.9	-1.0
P&P	4-MED RED	0.0	0.0	-0.4	-0.9	-1.9
P&P	5-HIGH RED	0.0	0.0	-0.4	-0.9	-1.9
EPG	1-BASE	0.0	0.0	0.0	0.0	0.0
EPG	2-GHG-Hg	-0.1	-2.8	-16.5	-19.3	-19.6
EPG	3-LOW RED	-0.1	-2.8	-26.7	-29.7	-29.6
EPG	4-MED RED	-0.1	-2.8	-25.4	-28.4	-44.0
EPG	5-HIGH RED	0.0	-3.2	-27.0	-42.3	-47.5
Gas	1-BASE	0.0	0.0	0.0	0.0	0.0
Gas	2-GHG-Hg	0.0	0.0	2.6	2.6	2.5
Gas	3-LOW RED	0.0	0.0	-11.3	-48.6	-90.1
Gas	4-MED RED	0.0	0.0	-37.2	-99.0	-138.1
Gas	5-HIGH RED	0.0	0.0	-60.1	-132.2	-138.1
Oil Conventional	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Conventional	2-GHG-Hg	0.0	0.0	2.3	2.3	1.5
Oil Conventional	3-LOW RED	0.0	0.0	2.3	2.3	1.5
Oil Conventional	4-MED RED	0.0	0.0	2.3	2.3	-0.3
Oil Conventional	5-HIGH RED	0.0	0.0	2.3	2.3	0.3
Oil refining	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil refining	2-GHG-Hg	0.0	-0.1	-0.1	-0.1	-0.1
Oil refining	3-LOW RED	0.0	-0.1	-0.1	-0.1	-0.1
Oil refining	4-MED RED	0.0	-0.1	-0.1	-0.1	-0.1
Oil refining	5-HIGH RED	0.0	-0.1	-0.1	-0.1	-0.1
Oil Sands	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Sands	2-GHG-Hg	-0.2	0.0	0.0	0.0	0.0
Oil Sands	3-LOW RED	-0.2	0.0	0.0	0.0	0.0
Oil Sands	4-MED RED	-0.1	0.0	0.0	0.0	-3.9
Oil Sands	5-HIGH RED	-0.2	0.0	0.0	0.0	-74.6
Wood Products	1-BASE	0.0	0.0	0.0	0.0	0.0
Wood Products	2-GHG-Hg	0.0	0.0	0.0	0.0	0.0
Wood Products	3-LOW RED	0.0	0.0	0.0	0.0	0.0
Wood Products	4-MED RED	0.0	0.0	0.0	0.0	-1.1
Wood Products	5-HIGH RED	0.0	0.0	0.0	0.0	-1.1

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Table II.13. Percentage reductions of NOx by sector

[illegible]	[illegible]	2010	[illegible]	[illegible]	[illegible]	[illegible]
Chemicals	1-BASE	0%	0%	0%	0%	0%
Chemicals	2-GHG-Hg	0%	0%	-22%	-33%	-34%
Chemicals	3-LOW RED	0%	0%	-32%	-41%	-43%
Chemicals	4-MED RED	0%	0%	-32%	-41%	-52%
Chemicals	5-HIGH RED	0%	0%	-32%	-47%	-52%
Cement	1-BASE	0%	0%	0%	0%	0%
Cement	2-GHG-Hg	0%	-21%	-37%	-46%	-50%
Cement	3-LOW RED	0%	-21%	-37%	-46%	-50%
Cement	4-MED RED	0%	-21%	-37%	-46%	-71%
Cement	5-HIGH RED	0%	-21%	-37%	-60%	-71%
P&P	1-BASE	0%	0%	0%	0%	0%
P&P	2-GHG-Hg	0%	0%	-10%	-20%	-20%
P&P	3-LOW RED	0%	0%	-10%	-20%	-20%
P&P	4-MED RED	0%	0%	-10%	-20%	-39%
P&P	5-HIGH RED	0%	0%	-10%	-20%	-39%
EPG	1-BASE	0%	0%	0%	0%	0%
EPG	2-GHG-Hg	0%	-3%	-17%	-19%	-19%
EPG	3-LOW RED	0%	-3%	-27%	-30%	-30%
EPG	4-MED RED	0%	-3%	-26%	-29%	-44%
EPG	5-HIGH RED	0%	-3%	-28%	-42%	-47%
Gas	1-BASE	0%	0%	0%	0%	0%
Gas	2-GHG-Hg	0%	0%	1%	1%	1%
Gas	3-LOW RED	0%	0%	-4%	-15%	-27%
Gas	4-MED RED	0%	0%	-12%	-30%	-41%
Gas	5-HIGH RED	0%	0%	-19%	-40%	-41%
Oil Conventional	1-BASE	0%	0%	0%	0%	0%
Oil Conventional	2-GHG-Hg	0%	0%	4%	5%	4%
Oil Conventional	3-LOW RED	0%	0%	4%	5%	4%
Oil Conventional	4-MED RED	0%	0%	4%	5%	-1%
Oil Conventional	5-HIGH RED	0%	0%	4%	5%	1%
Oil refining	1-BASE	0%	0%	0%	0%	0%
Oil refining	2-GHG-Hg	-1%	-1%	-3%	-3%	-3%
Oil refining	3-LOW RED	-1%	-1%	-3%	-3%	-3%
Oil refining	4-MED RED	0%	-1%	-3%	-3%	-3%
Oil refining	5-HIGH RED	0%	-1%	-3%	-3%	-3%
Oil Sands	1-BASE	0%	0%	0%	0%	0%
Oil Sands	2-GHG-Hg	0%	0%	0%	0%	0%
Oil Sands	3-LOW RED	0%	0%	0%	0%	0%
Oil Sands	4-MED RED	0%	0%	0%	0%	-2%
Oil Sands	5-HIGH RED	0%	0%	0%	0%	-44%
Wood Products	1-BASE	0%	0%	0%	0%	0%
Wood Products	2-GHG-Hg	0%	0%	0%	0%	0%
Wood Products	3-LOW RED	0%	0%	0%	0%	0%
Wood Products	4-MED RED	0%	0%	0%	0%	-16%
Wood Products	5-HIGH RED	0%	0%	0%	0%	-16%

Table II.12. NOx reductions by sector

NOx reductions kt		**2000**	**2005**	**2010**	**2015**	**2020**
Chemicals	1-BASE	0.0	0.0	0.0	0.0	0.0
Chemicals	2-GHG-Hg	0.0	0.0	-4.2	-7.4	-8.9
Chemicals	3-LOW RED	0.0	0.0	-6.1	-9.3	-11.1
Chemicals	4-MED RED	0.0	0.0	-6.1	-9.3	-13.5
Chemicals	5-HIGH RED	0.0	0.0	-6.1	-10.5	-13.5
Cement	1-BASE	0.0	0.0	0.0	0.0	0.0
Cement	2-GHG-Hg	0.0	-1.1	-2.1	-2.6	-3.0
Cement	3-LOW RED	0.0	-1.1	-2.1	-2.6	-3.0
Cement	4-MED RED	0.0	-1.1	-2.1	-2.6	-4.3
Cement	5-HIGH RED	0.0	-1.1	-2.1	-3.4	-4.3
P&P	1-BASE	0.0	0.0	0.0	0.0	0.0
P&P	2-GHG-Hg	0.0	0.0	-0.4	-0.9	-1.0
P&P	3-LOW RED	0.0	0.0	-0.4	-0.9	-1.0
P&P	4-MED RED	0.0	0.0	-0.4	-0.9	-1.9
P&P	5-HIGH RED	0.0	0.0	-0.4	-0.9	-1.9
EPG	1-BASE	0.0	0.0	0.0	0.0	0.0
EPG	2-GHG-Hg	-0.1	-2.8	-16.5	-19.3	-19.6
EPG	3-LOW RED	-0.1	-2.8	-26.7	-29.7	-29.6
EPG	4-MED RED	-0.1	-2.8	-25.4	-28.4	-44.0
EPG	5-HIGH RED	0.0	-3.2	-27.0	-42.3	-47.5
Gas	1-BASE	0.0	0.0	0.0	0.0	0.0
Gas	2-GHG-Hg	0.0	0.0	2.6	2.6	2.5
Gas	3-LOW RED	0.0	0.0	-11.3	-48.6	-90.1
Gas	4-MED RED	0.0	0.0	-37.2	-99.0	-138.1
Gas	5-HIGH RED	0.0	0.0	-60.1	-132.2	-138.1
Oil Conventional	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Conventional	2-GHG-Hg	0.0	0.0	2.3	2.3	1.5
Oil Conventional	3-LOW RED	0.0	0.0	2.3	2.3	1.5
Oil Conventional	4-MED RED	0.0	0.0	2.3	2.3	-0.3
Oil Conventional	5-HIGH RED	0.0	0.0	2.3	2.3	0.3
Oil refining	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil refining	2-GHG-Hg	0.0	-0.1	-0.1	-0.1	-0.1
Oil refining	3-LOW RED	0.0	-0.1	-0.1	-0.1	-0.1
Oil refining	4-MED RED	0.0	-0.1	-0.1	-0.1	-0.1
Oil refining	5-HIGH RED	0.0	-0.1	-0.1	-0.1	-0.1
Oil Sands	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Sands	2-GHG-Hg	-0.2	0.0	0.0	0.0	0.0
Oil Sands	3-LOW RED	-0.2	0.0	0.0	0.0	0.0
Oil Sands	4-MED RED	-0.1	0.0	0.0	0.0	-3.9
Oil Sands	5-HIGH RED	-0.2	0.0	0.0	0.0	-74.6
Wood Products	1-BASE	0.0	0.0	0.0	0.0	0.0
Wood Products	2-GHG-Hg	0.0	0.0	0.0	0.0	0.0
Wood Products	3-LOW RED	0.0	0.0	0.0	0.0	0.0
Wood Products	4-MED RED	0.0	0.0	0.0	0.0	-1.1
Wood Products	5-HIGH RED	0.0	0.0	0.0	0.0	-1.1

Table II.13. Percentage reductions of NOx by sector

NOx reductions %		2000	2005	2010	2015	2020
Chemicals	1-BASE	0%	0%	0%	0%	0%
Chemicals	2-GHG-Hg	0%	0%	-22%	-33%	-34%
Chemicals	3-LOW RED	0%	0%	-32%	-41%	-43%
Chemicals	4-MED RED	0%	0%	-32%	-41%	-52%
Chemicals	5-HIGH RED	0%	0%	-32%	-47%	-52%
Cement	1-BASE	0%	0%	0%	0%	0%
Cement	2-GHG-Hg	0%	-21%	-37%	-46%	-50%
Cement	3-LOW RED	0%	-21%	-37%	-46%	-50%
Cement	4-MED RED	0%	-21%	-37%	-46%	-71%
Cement	5-HIGH RED	0%	-21%	-37%	-60%	-71%
P&P	1-BASE	0%	0%	0%	0%	0%
P&P	2-GHG-Hg	0%	0%	-10%	-20%	-20%
P&P	3-LOW RED	0%	0%	-10%	-20%	-20%
P&P	4-MED RED	0%	0%	-10%	-20%	-39%
P&P	5-HIGH RED	0%	0%	-10%	-20%	-39%
EPG	1-BASE	0%	0%	0%	0%	0%
EPG	2-GHG-Hg	0%	-3%	-17%	-19%	-19%
EPG	3-LOW RED	0%	-3%	-27%	-30%	-30%
EPG	4-MED RED	0%	-3%	-26%	-29%	-44%
EPG	5-HIGH RED	0%	-3%	-28%	-42%	-47%
Gas	1-BASE	0%	0%	0%	0%	0%
Gas	2-GHG-Hg	0%	0%	1%	1%	1%
Gas	3-LOW RED	0%	0%	-4%	-15%	-27%
Gas	4-MED RED	0%	0%	-12%	-30%	-41%
Gas	5-HIGH RED	0%	0%	-19%	-40%	-41%
Oil Conventional	1-BASE	0%	0%	0%	0%	0%
Oil Conventional	2-GHG-Hg	0%	0%	4%	5%	4%
Oil Conventional	3-LOW RED	0%	0%	4%	5%	4%
Oil Conventional	4-MED RED	0%	0%	4%	5%	-1%
Oil Conventional	5-HIGH RED	0%	0%	4%	5%	1%
Oil refining	1-BASE	0%	0%	0%	0%	0%
Oil refining	2-GHG-Hg	-1%	-1%	-3%	-3%	-3%
Oil refining	3-LOW RED	-1%	-1%	-3%	-3%	-3%
Oil refining	4-MED RED	0%	-1%	-3%	-3%	-3%
Oil refining	5-HIGH RED	0%	-1%	-3%	-3%	-3%
Oil Sands	1-BASE	0%	0%	0%	0%	0%
Oil Sands	2-GHG-Hg	0%	0%	0%	0%	0%
Oil Sands	3-LOW RED	0%	0%	0%	0%	0%
Oil Sands	4-MED RED	0%	0%	0%	0%	-2%
Oil Sands	5-HIGH RED	0%	0%	0%	0%	-44%
Wood Products	1-BASE	0%	0%	0%	0%	0%
Wood Products	2-GHG-Hg	0%	0%	0%	0%	0%
Wood Products	3-LOW RED	0%	0%	0%	0%	0%
Wood Products	4-MED RED	0%	0%	0%	0%	-16%
Wood Products	5-HIGH RED	0%	0%	0%	0%	-16%

Table II.14. Emissions of SOx by sector

SOx emissions kt/y		2000	2005	2010	2015	2020
Cement	1-BASE	2.9	3.2	3.4	3.3	3.6
Cement	2-GHG-Hg	2.9	2.5	2.2	1.8	1.8
Cement	3-LOW RED	2.9	2.5	2.2	1.8	1.8
Cement	4-MED RED	2.9	2.5	2.2	1.5	1.5
Cement	5-HIGH RED	2.9	2.5	1.9	1.5	0.5
P&P	1-BASE	2.0	2.2	2.3	2.4	2.6
P&P	2-GHG-Hg	2.0	2.2	2.1	1.9	2.1
P&P	3-LOW RED	2.0	2.2	2.1	1.9	2.1
P&P	4-MED RED	2.0	2.2	2.1	1.9	2.1
P&P	5-HIGH RED	2.0	2.2	2.1	1.9	0.9
EPG	1-BASE	128.1	126.1	129.3	135.0	135.0
EPG	2-GHG-Hg	128.1	123.9	116.4	115.2	114.6
EPG	3-LOW RED	128.1	123.9	116.4	114.6	114.6
EPG	4-MED RED	128.1	123.9	116.4	114.6	97.2
EPG	5-HIGH RED	128.1	123.7	116.3	78.3	11.2
Gas	1-BASE	227.5	216.4	210.9	210.4	208.9
Gas	2-GHG-Hg	227.5	216.4	162.5	153.5	152.0
Gas	3-LOW RED	227.5	216.4	162.5	153.5	152.0
Gas	4-MED RED	227.5	216.4	160.2	108.0	58.9
Gas	5-HIGH RED	227.5	216.4	114.8	46.9	44.2
Oil Conventional	1-BASE	32.4	19.4	18.5	18.0	16.3
Oil Conventional	2-GHG-Hg	32.4	19.4	18.5	17.9	16.3
Oil Conventional	3-LOW RED	32.4	19.4	18.5	17.9	16.3
Oil Conventional	4-MED RED	32.4	19.4	18.5	17.9	16.3
Oil Conventional	5-HIGH RED	32.4	19.4	18.5	17.9	16.3
Oil refining	1-BASE	13.1	12.2	12.4	15.4	15.8
Oil refining	2-GHG-Hg	13.0	12.1	12.1	15.0	15.4
Oil refining	3-LOW RED	13.0	12.1	12.1	15.0	15.4
Oil refining	4-MED RED	13.0	12.1	12.1	9.8	10.1
Oil refining	5-HIGH RED	13.0	12.1	7.9	7.1	7.0
Oil Sands	1-BASE	94.0	116.9	168.7	173.7	164.0
Oil Sands	2-GHG-Hg	93.6	116.9	168.7	173.7	164.0
Oil Sands	3-LOW RED	93.6	116.9	168.7	173.7	164.0
Oil Sands	4-MED RED	93.7	116.9	168.7	173.7	164.0
Oil Sands	5-HIGH RED	93.6	116.9	168.7	173.7	120.1

Table II.15. Reductions of SOx by sector

SOx reductions kt		2000	2005	2010	2015	2020
Cement	1-BASE	0.0	0.0	0.0	0.0	0.0
Cement	2-GHG-Hg	0.0	-0.7	-1.2	-1.5	-1.8
Cement	3-LOW RED	0.0	-0.7	-1.2	-1.5	-1.8
Cement	4-MED RED	0.0	-0.7	-1.2	-1.8	-2.1
Cement	5-HIGH RED	0.0	-0.7	-1.5	-1.8	-3.1
P&P	1-BASE	0.0	0.0	0.0	0.0	0.0
P&P	2-GHG-Hg	0.0	0.0	-0.2	-0.5	-0.5
P&P	3-LOW RED	0.0	0.0	-0.2	-0.5	-0.5
P&P	4-MED RED	0.0	0.0	-0.2	-0.5	-0.5
P&P	5-HIGH RED	0.0	0.0	-0.2	-0.5	-1.7
EPG	1-BASE	0.0	0.0	0.0	0.0	0.0
EPG	2-GHG-Hg	0.0	-2.2	-12.9	-19.8	-20.4
EPG	3-LOW RED	0.0	-2.2	-12.9	-20.4	-20.4
EPG	4-MED RED	0.0	-2.2	-12.9	-20.4	-37.8
EPG	5-HIGH RED	0.0	-2.3	-13.0	-56.7	-123.8
Gas	1-BASE	0.0	0.0	0.0	0.0	0.0
Gas	2-GHG-Hg	0.0	0.0	-48.4	-56.9	-56.9
Gas	3-LOW RED	0.0	0.0	-48.4	-56.9	-56.9
Gas	4-MED RED	0.0	0.0	-50.7	-102.5	-150.0
Gas	5-HIGH RED	0.0	0.0	-96.1	-163.5	-164.7
Oil Conventional	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Conventional	2-GHG-Hg	0.0	0.0	0.0	0.0	0.0
Oil Conventional	3-LOW RED	0.0	0.0	0.0	0.0	0.0
Oil Conventional	4-MED RED	0.0	0.0	0.0	0.0	0.0
Oil Conventional	5-HIGH RED	0.0	0.0	0.0	0.0	0.0
Oil refining	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil refining	2-GHG-Hg	-0.1	-0.2	-0.3	-0.4	-0.4
Oil refining	3-LOW RED	-0.1	-0.2	-0.3	-0.4	-0.4
Oil refining	4-MED RED	0.0	-0.1	-0.3	-5.6	-5.7
Oil refining	5-HIGH RED	-0.1	-0.2	-4.5	-8.3	-8.9
Oil Sands	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Sands	2-GHG-Hg	-0.4	0.0	0.0	0.0	0.0
Oil Sands	3-LOW RED	-0.4	0.0	0.0	0.0	0.0
Oil Sands	4-MED RED	-0.3	0.0	0.0	0.0	0.0
Oil Sands	5-HIGH RED	-0.3	0.0	0.0	0.0	-43.9

Table II.14. Emissions of SOx by sector

SOx emissions kt/y		2000	2005	2010	2015	2020
Cement	1-BASE	2.9	3.2	3.4	3.3	3.6
Cement	2-GHG-Hg	2.9	2.5	2.2	1.8	1.8
Cement	3-LOW RED	2.9	2.5	2.2	1.8	1.8
Cement	4-MED RED	2.9	2.5	2.2	1.5	1.5
Cement	5-HIGH RED	2.9	2.5	1.9	1.5	0.5
P&P	1-BASE	2.0	2.2	2.3	2.4	2.6
P&P	2-GHG-Hg	2.0	2.2	2.1	1.9	2.1
P&P	3-LOW RED	2.0	2.2	2.1	1.9	2.1
P&P	4-MED RED	2.0	2.2	2.1	1.9	2.1
P&P	5-HIGH RED	2.0	2.2	2.1	1.9	0.9
EPG	1-BASE	128.1	126.1	129.3	135.0	135.0
EPG	2-GHG-Hg	128.1	123.9	116.4	115.2	114.6
EPG	3-LOW RED	128.1	123.9	116.4	114.6	114.6
EPG	4-MED RED	128.1	123.9	116.4	114.6	97.2
EPG	5-HIGH RED	128.1	123.7	116.3	78.3	11.2
Gas	1-BASE	227.5	216.4	210.9	210.4	208.9
Gas	2-GHG-Hg	227.5	216.4	162.5	153.5	152.0
Gas	3-LOW RED	227.5	216.4	162.5	153.5	152.0
Gas	4-MED RED	227.5	216.4	160.2	108.0	58.9
Gas	5-HIGH RED	227.5	216.4	114.8	46.9	44.2
Oil Conventional	1-BASE	32.4	19.4	18.5	18.0	16.3
Oil Conventional	2-GHG-Hg	32.4	19.4	18.5	17.9	16.3
Oil Conventional	3-LOW RED	32.4	19.4	18.5	17.9	16.3
Oil Conventional	4-MED RED	32.4	19.4	18.5	17.9	16.3
Oil Conventional	5-HIGH RED	32.4	19.4	18.5	17.9	16.3
Oil refining	1-BASE	13.1	12.2	12.4	15.4	15.8
Oil refining	2-GHG-Hg	13.0	12.1	12.1	15.0	15.4
Oil refining	3-LOW RED	13.0	12.1	12.1	15.0	15.4
Oil refining	4-MED RED	13.0	12.1	12.1	9.8	10.1
Oil refining	5-HIGH RED	13.0	12.1	7.9	7.1	7.0
Oil Sands	1-BASE	94.0	116.9	168.7	173.7	164.0
Oil Sands	2-GHG-Hg	93.6	116.9	168.7	173.7	164.0
Oil Sands	3-LOW RED	93.6	116.9	168.7	173.7	164.0
Oil Sands	4-MED RED	93.7	116.9	168.7	173.7	164.0
Oil Sands	5-HIGH RED	93.6	116.9	168.7	173.7	120.1

Table II.15. Reductions of SOx by sector

SOx reductions kt		2000	2005	2010	2015	2020
Cement	1-BASE	0.0	0.0	0.0	0.0	0.0
Cement	2-GHG-Hg	0.0	-0.7	-1.2	-1.5	-1.8
Cement	3-LOW RED	0.0	-0.7	-1.2	-1.5	-1.8
Cement	4-MED RED	0.0	-0.7	-1.2	-1.8	-2.1
Cement	5-HIGH RED	0.0	-0.7	-1.5	-1.8	-3.1
P&P	1-BASE	0.0	0.0	0.0	0.0	0.0
P&P	2-GHG-Hg	0.0	0.0	-0.2	-0.5	-0.5
P&P	3-LOW RED	0.0	0.0	-0.2	-0.5	-0.5
P&P	4-MED RED	0.0	0.0	-0.2	-0.5	-0.5
P&P	5-HIGH RED	0.0	0.0	-0.2	-0.5	-1.7
EPG	1-BASE	0.0	0.0	0.0	0.0	0.0
EPG	2-GHG-Hg	0.0	-2.2	-12.9	-19.8	-20.4
EPG	3-LOW RED	0.0	-2.2	-12.9	-20.4	-20.4
EPG	4-MED RED	0.0	-2.2	-12.9	-20.4	-37.8
EPG	5-HIGH RED	0.0	-2.3	-13.0	-56.7	-123.8
Gas	1-BASE	0.0	0.0	0.0	0.0	0.0
Gas	2-GHG-Hg	0.0	0.0	-48.4	-56.9	-56.9
Gas	3-LOW RED	0.0	0.0	-48.4	-56.9	-56.9
Gas	4-MED RED	0.0	0.0	-50.7	-102.5	-150.0
Gas	5-HIGH RED	0.0	0.0	-96.1	-163.5	-164.7
Oil Conventional	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Conventional	2-GHG-Hg	0.0	0.0	0.0	0.0	0.0
Oil Conventional	3-LOW RED	0.0	0.0	0.0	0.0	0.0
Oil Conventional	4-MED RED	0.0	0.0	0.0	0.0	0.0
Oil Conventional	5-HIGH RED	0.0	0.0	0.0	0.0	0.0
Oil refining	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil refining	2-GHG-Hg	-0.1	-0.2	-0.3	-0.4	-0.4
Oil refining	3-LOW RED	-0.1	-0.2	-0.3	-0.4	-0.4
Oil refining	4-MED RED	0.0	-0.1	-0.3	-5.6	-5.7
Oil refining	5-HIGH RED	-0.1	-0.2	-4.5	-8.3	-8.9
Oil Sands	1-BASE	0.0	0.0	0.0	0.0	0.0
Oil Sands	2-GHG-Hg	-0.4	0.0	0.0	0.0	0.0
Oil Sands	3-LOW RED	-0.4	0.0	0.0	0.0	0.0
Oil Sands	4-MED RED	-0.3	0.0	0.0	0.0	0.0
Oil Sands	5-HIGH RED	-0.3	0.0	0.0	0.0	-43.9

Table II.16. Percentage reductions of SOx by sector

SOx reductions %		2000	2005	2010	2015	2020
Cement	1-BASE	0%	0%	0%	0%	0%
Cement	2-GHG-Hg	0%	-22%	-35%	-45%	-50%
Cement	3-LOW RED	0%	-22%	-35%	-45%	-50%
Cement	4-MED RED	0%	-22%	-35%	-55%	-58%
Cement	5-HIGH RED	0%	-22%	-44%	-55%	-86%
P&P	1-BASE	0%	0%	0%	0%	0%
P&P	2-GHG-Hg	0%	0%	-9%	-21%	-19%
P&P	3-LOW RED	0%	0%	-9%	-21%	-19%
P&P	4-MED RED	0%	0%	-9%	-21%	-19%
P&P	5-HIGH RED	0%	0%	-9%	-21%	-65%
EPG	1-BASE	0%	0%	0%	0%	0%
EPG	2-GHG-Hg	0%	-2%	-10%	-15%	-15%
EPG	3-LOW RED	0%	-2%	-10%	-15%	-15%
EPG	4-MED RED	0%	-2%	-10%	-15%	-28%
EPG	5-HIGH RED	0%	-2%	-10%	-42%	-92%
Gas	1-BASE	0%	0%	0%	0%	0%
Gas	2-GHG-Hg	0%	0%	-23%	-27%	-27%
Gas	3-LOW RED	0%	0%	-23%	-27%	-27%
Gas	4-MED RED	0%	0%	-24%	-49%	-72%
Gas	5-HIGH RED	0%	0%	-46%	-78%	-79%
Oil Conventional	1-BASE	0%	0%	0%	0%	0%
Oil Conventional	2-GHG-Hg	0%	0%	0%	0%	0%
Oil Conventional	3-LOW RED	0%	0%	0%	0%	0%
Oil Conventional	4-MED RED	0%	0%	0%	0%	0%
Oil Conventional	5-HIGH RED	0%	0%	0%	0%	0%
Oil refining	1-BASE	0%	0%	0%	0%	0%
Oil refining	2-GHG-Hg	-1%	-1%	-3%	-3%	-3%
Oil refining	3-LOW RED	-1%	-1%	-3%	-3%	-3%
Oil refining	4-MED RED	0%	-1%	-3%	-36%	-36%
Oil refining	5-HIGH RED	0%	-1%	-36%	-54%	-56%
Oil Sands	1-BASE	0%	0%	0%	0%	0%
Oil Sands	2-GHG-Hg	0%	0%	0%	0%	0%
Oil Sands	3-LOW RED	0%	0%	0%	0%	0%
Oil Sands	4-MED RED	0%	0%	0%	0%	0%
Oil Sands	5-HIGH RED	0%	0%	0%	0%	-27%

Table II.16. Percentage reductions of SOx by sector

SOx reductions	[illegible]	2000	2005	2010	2015	2020
Cement	1-BASE	0%	0%	0%	0%	0%
Cement	2-GHG-Hg	0%	-22%	-35%	-45%	-50%
Cement	3-LOW RED	0%	-22%	-35%	-45%	-50%
Cement	4-MED RED	0%	-22%	-35%	-55%	-58%
Cement	5-HIGH RED	0%	-22%	-44%	-55%	-86%
P&P	1-BASE	0%	0%	0%	0%	0%
P&P	2-GHG-Hg	0%	0%	-9%	-21%	-19%
P&P	3-LOW RED	0%	0%	-9%	-21%	-19%
P&P	4-MED RED	0%	0%	-9%	-21%	-19%
P&P	5-HIGH RED	0%	0%	-9%	-21%	-65%
EPG	1-BASE	0%	0%	0%	0%	0%
EPG	2-GHG-Hg	0%	-2%	-10%	-15%	-15%
EPG	3-LOW RED	0%	-2%	-10%	-15%	-15%
EPG	4-MED RED	0%	-2%	-10%	-15%	-28%
EPG	5-HIGH RED	0%	-2%	-10%	-42%	-92%
Gas	1-BASE	0%	0%	0%	0%	0%
Gas	2-GHG-Hg	0%	0%	-23%	-27%	-27%
Gas	3-LOW RED	0%	0%	-23%	-27%	-27%
Gas	4-MED RED	0%	0%	-24%	-49%	-72%
Gas	5-HIGH RED	0%	0%	-46%	-78%	-79%
Oil Conventional	1-BASE	0%	0%	0%	0%	0%
Oil Conventional	2-GHG-Hg	0%	0%	0%	0%	0%
Oil Conventional	3-LOW RED	0%	0%	0%	0%	0%
Oil Conventional	4-MED RED	0%	0%	0%	0%	0%
Oil Conventional	5-HIGH RED	0%	0%	0%	0%	0%
Oil refining	1-BASE	0%	0%	0%	0%	0%
Oil refining	2-GHG-Hg	-1%	-1%	-3%	-3%	-3%
Oil refining	3-LOW RED	-1%	-1%	-3%	-3%	-3%
Oil refining	4-MED RED	0%	-1%	-3%	-36%	-36%
Oil refining	5-HIGH RED	0%	-1%	-36%	-54%	-56%
Oil Sands	1-BASE	0%	0%	0%	0%	0%
Oil Sands	2-GHG-Hg	0%	0%	0%	0%	0%
Oil Sands	3-LOW RED	0%	0%	0%	0%	0%
Oil Sands	4-MED RED	0%	0%	0%	0%	0%
Oil Sands	5-HIGH RED	0%	0%	0%	0%	-27%

2.5 Regional Emissions

Table 17 shows regional emissions and, more importantly, the percentage reductions (in 2020) of each pollutant in each region, relative to period 2000.

Only Region 16 (North East oil sands region around Fort McMurray) shows emissions of NOx and SOx that grow over time. Emissions in this region are predominantly from the oil sands sector, which undergoes a rapid growth of activity and implements very few reductions except in Case 5, as seen in the previous section.

- In Cases 2 to 4, emissions of NOx and SOx are almost as high as those of the Base case.
- In Case 5, the increase of NOx and SOx emissions from 2000 to 2020 is still positive, but it now less than one third of what it is in Base (+20% instead of +68% for SOx, and +53% instead of +169% for NOx). If these increases are judged acceptable, then Case 5 would not require any special constraint on NOx and SOx in region 16.
- Note also that imposing drastic emission reductions on region 16 might be quite costly, since the oil sands sector grows very rapidly from 2000 to 2020, and, therefore, a severe constraint might have the effect of reducing that growth.

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Table 17. Emissions and reductions by region

		BASE emission 2000	Case 1 emissions		Change in 2020 wrt yr 2000	Case 2 emissions		Change in 2020 wrt yr 2000	Case 3 emissions		Change in 2020 wrt yr 2000	Case 4 emissions		Change in 2020 wrt yr 2000	Case 5 emissions		Change in 2020 wrt yr 2000
			2010	2020		2010	2020		2010	2020		2010	2020		2010	2020	
Reg 01	NOx kt/y	21	25	27	28%	25	26	21%	24	21	-4%	23	17	-20%	21	17	-20%
	SOx kt/y	2	2	2	-13%	2	1	-35%	2	1	-35%	2	1	-71%	1	1	-77%
	Hg kg/y	0	0	0	–	0	0	–	0	0	–	0	0	–	0	0	–
Reg 02	NOx kt/y	12	20	25	100%	15	15	22%	14	12	-7%	13	10	-22%	12	10	-22%
	SOx kt/y	13	19	26	96%	9	9	-35%	9	9	-35%	9	4	-71%	7	3	-77%
	Hg kg/y	0	75	144		0	0		0	0		0	0		0	0	
Reg 03	NOx kt/y	10	11	12	20%	11	12	22%	11	9	-7%	10	7	-22%	10	8	-22%
	SOx kt/y	12	11	11	-13%	9	8	-35%	9	8	-35%	8	4	-71%	6	3	-77%
	Hg kg/y	0	0	0	–	0	0	–	0	0	–	0	0	–	0	0	–
Reg 04	NOx kt/y	31	34	34	12%	34	35	13%	32	27	-10%	30	22	-27%	28	23	-23%
	SOx kt/y	35	34	34	-1%	34	34	-1%	34	34	-1%	34	29	-15%	34	2	-94%
	Hg kg/y	76	76	76	0%	38	38	-50%	38	38	-50%	38	38	-50%	38	38	-50%
Reg 05	NOx kt/y	18	22	22	20%	22	23	22%	21	17	-7%	20	14	-22%	18	14	-22%
	SOx kt/y	8	7	7	-13%	6	5	-35%	6	5	-35%	5	2	-71%	4	2	-77%
	Hg kg/y	0	0	0	–	0	0	–	0	0	–	0	0	–	0	0	–
Reg 06	NOx kt/y	34	42	43	26%	42	43	25%	40	33	-3%	38	28	-19%	35	28	-19%
	SOx kt/y	65	57	56	-13%	45	42	-35%	45	42	-35%	45	19	-71%	33	15	-77%
	Hg kg/y	0	0	0	–	0	0	–	0	0	–	0	0	–	0	0	–
Reg 07	NOx kt/y	26	28	28	9%	28	28	10%	26	23	-13%	25	15	-41%	24	15	-41%
	SOx kt/y	29	28	28	-4%	27	27	-10%	27	27	-10%	27	13	-56%	25	2	-92%
	Hg kg/y	98	98	98	0%	49	49	-50%	49	49	-50%	49	49	-50%	49	49	-50%
Reg 08	NOx kt/y	23	28	29	27%	27	28	21%	26	22	-4%	25	19	-18%	23	19	-17%
	SOx kt/y	12	10	10	-13%	8	8	-35%	8	8	-35%	8	3	-71%	6	3	-77%
	Hg kg/y	0	0	0	–	0	0	–	0	0	–	0	0	–	0	0	–

Table 17. Emissions and reductions by region

		BASE emission 2000	Case 1 emissions		Change in 2020 wrt yr 2000	Case 2 emission		Change in 2020 wrt yr 2000	Case 3 emissions		Change in 2020 wrt yr 2000	Case 4 emissions		Change in 2020 wrt yr 2000	Case 5 emissions		Change in 2020 wrt yr 2000
			2010	2020		2010	2020		2010	2020		2010	2020		2010	2020	
Reg 09	**NOx kt/y**	16	18	19	20%	19	19	22%	18	15	-7%	17	12	-22%	16	12	-22%
	SOx kt/y	25	22	21	-13%	17	16	-35%	17	16	-35%	17	7	-71%	13	6	-77%
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–
Reg 10	**NOx kt/y**	14	16	16	20%	16	17	22%	16	13	-7%	14	11	-22%	14	11	-21%
	SOx kt/y	4	4	4	-13%	3	3	-35%	3	3	-35%	3	1	-71%	2	1	-76%
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–
Reg 11	**NOx kt/y**	95	109	113	19%	97	99	4%	87	83	-13%	86	72	-25%	84	65	-32%
	SOx kt/y	102	99	100	-1%	92	94	-8%	92	94	-8%	92	84	-18%	86	28	-73%
	Hg kg/y	545	666	660	21%	290	287	-50%	290	287	-50%	290	287	-50%	284	281	-50%
Reg 12	**NOx kt/y**	19	28	30	53%	29	30	54%	28	25	30%	27	23	16%	26	18	-5%
	SOx kt/y	9	11	11	29%	11	10	18%	11	10	18%	11	9	-1%	10	6	-26%
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–
Reg 13	**NOx kt/y**	18	21	22	21%	22	22	20%	21	17	-6%	20	15	-20%	18	15	-20%
	SOx kt/y	33	29	29	-13%	23	21	-35%	23	21	-35%	23	10	-71%	17	8	-76%
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–
Reg 14	**NOx kt/y**	14	16	16	20%	16	16	21%	16	13	-6%	15	11	-21%	14	11	-21%
	SOx kt/y	15	13	13	-13%	11	10	-35%	11	10	-35%	10	4	-70%	8	4	-76%
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–
Reg 15	**NOx kt/y**	6	7	8	23%	6	5	-14%	6	5	-25%	5	3	-52%	5	3	-52%
	SOx kt/y	11	10	10	-4%	8	7	-36%	8	7	-36%	8	4	-65%	6	2	-79%
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–
Reg 16	**NOx kt/y**	63	159	169	**169%**	157	169	**169%**	157	166	**164%**	156	161	**156%**	155	96	**53%**
	SOx kt/y	89	154	150	**68%**	153	149	**67%**	153	149	**67%**	153	146	**64%**	152	107	**20%**
	Hg kg/y	0	0	0	–	0	0	--	0	0	--	0	0	–	0	0	–

Table 17. Emissions and reductions by region

		BASE emission 2000	Case 1 emissions		Change in 2020 wrt yr 2000	Case 2 emissions		Change in 2020 wrt yr 2000	Case 3 emissions		Change in 2020 wrt yr 2000	Case 4 emissions		Change in 2020 wrt yr 2000	Case 5 emissions		Change in 2020 wrt yr 2000
			2010	2020		2010	2020		2010	2020		2010	2020		2010	2020	
Reg 01	NOx kt/y	**21**	25	27	28%	25	26	21%	24	21	-4%	23	17	-20%	21	17	-20%
	SOx kt/y	**2**	2	2	-13%	2	1	-35%	2	1	-35%	2	1	-71%	1	1	-77%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 02	NOx kt/y	**12**	20	25	100%	15	15	22%	14	12	-7%	13	10	-22%	12	10	-22%
	SOx kt/y	**13**	19	26	96%	9	9	-35%	9	9	-35%	9	4	-71%	7	3	-77%
	Hg kg/y	**0**	75	144		0	0		0	0		0	0		0	0	
Reg 03	NOx kt/y	**10**	11	12	20%	11	12	22%	11	9	-7%	10	7	-22%	10	8	-22%
	SOx kt/y	**12**	11	11	-13%	9	8	-35%	9	8	-35%	8	4	-71%	6	3	-77%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 04	NOx kt/y	**31**	34	34	12%	34	35	13%	32	27	-10%	30	22	-27%	28	23	-23%
	SOx kt/y	**35**	34	34	-1%	34	34	-1%	34	34	-1%	34	29	-15%	34	2	-94%
	Hg kg/y	**76**	76	76	0%	38	38	-50%	38	38	-50%	38	38	-50%	38	38	-50%
Reg 05	NOx kt/y	**18**	22	22	20%	22	23	22%	21	17	-7%	20	14	-22%	18	14	-22%
	SOx kt/y	**8**	7	7	-13%	6	5	-35%	6	5	-35%	5	2	-71%	4	2	-77%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 06	NOx kt/y	**34**	42	43	26%	42	43	25%	40	33	-3%	38	28	-19%	35	28	-19%
	SOx kt/y	**65**	57	56	-13%	45	42	-35%	45	42	-35%	45	19	-71%	33	15	-77%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 07	NOx kt/y	**26**	28	28	9%	28	28	10%	26	23	-13%	25	15	-41%	24	15	-41%
	SOx kt/y	**29**	28	28	-4%	27	27	-10%	27	27	-10%	27	13	-56%	25	2	-92%
	Hg kg/y	**98**	98	98	0%	49	49	-50%	49	49	-50%	49	49	-50%	49	49	-50%
Reg 08	NOx kt/y	**23**	28	29	27%	27	28	21%	26	22	-4%	25	19	-18%	23	19	-17%
	SOx kt/y	**12**	10	10	-13%	8	8	-35%	8	8	-35%	8	3	-71%	6	3	-77%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--

Table 17. Emissions and reductions by region

		BASE emission 2000	Case 1 emissions		Change in 2020 wrt yr 2000	Case 2 emissions		Change in 2020 wrt yr 2000	Case 3 emissions		Change in 2020 wrt yr 2000	Case 4 emissions		Change in 2020 wrt yr 2000	Case 5 emissions		Change in 2020 wrt yr 2000
			2010	2020		2010	2020		2010	2020		2010	2020		2010	2020	
Reg 09	NOx kt/y	**16**	18	19	20%	19	19	22%	18	15	-7%	17	12	-22%	16	12	-22%
	SOx kt/y	**25**	22	21	-13%	17	16	-35%	17	16	-35%	17	7	-71%	13	6	-77%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 10	NOx kt/y	**14**	16	16	20%	16	17	22%	16	13	-7%	14	11	-22%	14	11	-21%
	SOx kt/y	**4**	4	4	-13%	3	3	-35%	3	3	-35%	3	1	-71%	2	1	-76%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 11	NOx kt/y	**95**	109	113	19%	97	99	4%	87	83	-13%	86	72	-25%	84	65	-32%
	SOx kt/y	**102**	99	100	-1%	92	94	-8%	92	94	-8%	92	84	-18%	86	28	-73%
	Hg kg/y	**545**	666	660	21%	290	287	-50%	290	287	-50%	290	287	-50%	284	281	-50%
Reg 12	NOx kt/y	**19**	28	30	53%	29	30	54%	28	25	30%	27	23	16%	26	18	-5%
	SOx kt/y	**9**	11	11	29%	11	10	18%	11	10	18%	11	9	-1%	10	6	-26%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 13	NOx kt/y	**18**	21	22	21%	22	22	20%	21	17	-6%	20	15	-20%	18	15	-20%
	SOx kt/y	**33**	29	29	-13%	23	21	-35%	23	21	-35%	23	10	-71%	17	8	-76%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 14	NOx kt/y	**14**	16	16	20%	16	16	21%	16	13	-6%	15	11	-21%	14	11	-21%
	SOx kt/y	**15**	13	13	-13%	11	10	-35%	11	10	-35%	10	4	-70%	8	4	-76%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 15	NOx kt/y	**6**	7	8	23%	6	5	-14%	6	5	-25%	5	3	-52%	5	3	-52%
	SOx kt/y	**11**	10	10	-4%	8	7	-36%	8	7	-36%	8	4	-65%	6	2	-79%
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 16	NOx kt/y	**63**	159	169	**169%**	157	169	**169%**	157	166	**164%**	156	161	**156%**	155	96	**53%**
	SOx kt/y	**89**	154	150	**68%**	153	149	**67%**	153	149	**67%**	153	146	**64%**	152	107	**20%**
	Hg kg/y	**0**	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--

Table 17. Emissions and reductions by region

		BASE emission 2000	Case 1 emissions		Change in 2020 wrt yr 2000	Case 2 emissions		Change in 2020 wrt yr 2000	Case 3 emissions		Change in 2020 wrt yr 2000	Case 4 emissions		Change in 2020 wrt yr 2000	Case 5 emissions		Change in 2020 wrt yr 2000
			2010	2020		2010	2020		2010	2020		2010	2020		2010	2020	
Reg 17	NOx kt/y	32	37	38	20%	38	38	21%	36	29	-7%	34	25	-22%	32	25	-21%
	SOx kt/y	9	8	8	-12%	7	6	-34%	7	6	-34%	6	3	-68%	5	2	-74%
	Hg kg/y	0	0	0	--	0	0	—	0	0	—	0	0	—	0	0	--
Reg 18	NOx kt/y	23	26	27	20%	27	27	22%	26	21	-7%	24	18	-22%	23	18	-22%
	SOx kt/y	14	12	12	-13%	10	9	-35%	10	9	-35%	10	4	-71%	7	3	-77%
	Hg kg/y	0	0	0	—	0	0	—	0	0	--	0	0	—	0	0	--
Reg 19	NOx kt/y	17	19	19	17%	18	18	7%	17	14	-16%	16	10	-41%	15	10	-41%
	SOx kt/y	13	13	13	-4%	9	8	-37%	9	8	-37%	9	3	-74%	8	2	-86%
	Hg kg/y	24	24	24	0%	12	12	-50%	12	12	-50%	12	0	-100%	12	0	-100%
ALBERTA	NOx kt/y	491	666	698	42%	647	670	36%	621	565	15%	597	491	0%	572	418	-15%
	SOx kt/y	500	546	546	9%	483	466	-7%	483	466	-7%	480	350	-30%	430	200	-60%
	Hg kg/y	744	940	1002	35%	389	386	-48%	389	386	-48%	389	374	-50%	383	368	-50%

Table 17. Emissions and reductions by region

		[illegible] emission 2000	Case 1 emissions		Change in 2020 wrt yr 2000	Case 2 emissions		Change in 2020 wrt yr 2000	Case 3 emissions		Change in 2020 wrt yr 2000	Case 4 emissions		Change in 2020 wrt yr 2000	Case 5 emissions		Change in 2020 wrt yr 2000
			2010	2020		2010	2020		2010	2020		2010	2020		2010	2020	
Reg 17	NOx kt/y	32	37	38	20%	38	38	21%	36	29	-7%	34	25	-22%	32	25	-21%
	SOx kt/y	9	8	8	-12%	7	6	-34%	7	6	-34%	6	3	-68%	5	2	-74%
	Hg kg/y	0	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 18	NOx kt/y	23	26	27	20%	27	27	22%	26	21	-7%	24	18	-22%	23	18	-22%
	SOx kt/y	14	12	12	-13%	10	9	-35%	10	9	-35%	10	4	-71%	7	3	-77%
	Hg kg/y	0	0	0	--	0	0	--	0	0	--	0	0	--	0	0	--
Reg 19	NOx kt/y	17	19	19	17%	18	18	7%	17	14	-16%	16	10	-41%	15	10	-41%
	SOx kt/y	13	13	13	-4%	9	8	-37%	9	8	-37%	9	3	-74%	8	2	-86%
	Hg kg/y	24	24	24	0%	12	12	-50%	12	12	-50%	12	0	-100%	12	0	-100%
ALBERTA	NOx kt/y	491	666	698	42%	647	670	36%	621	565	15%	597	491	0%	572	418	-15%
	SOx kt/y	500	546	546	9%	483	466	-7%	483	466	-7%	480	350	-30%	430	200	-60%
	Hg kg/y	[illegible]	940	1002	35%	389	386	-48%	389	386	-48%	389	374	-50%	383	368	-50%

2.6 Profits

Provided below are results on changes in profits for all covered sectors together (Table II.18), and another one (Table II.20) of individual sectors' profits. We first make some general remarks:

- Profits should *not* be identified to surplus. Profits accrue to suppliers, whereas surpluses concern both suppliers and consumers. Therefore, the profit picture given in this section is only addressing a portion of the overall surpluses shown in section.
- Profits should not be taken too literally (at this stage) since they do not yet take into account the trading of permits. When permit allowances are simulated, the profits are quite likely to change drastically from the numbers shown in the following tables.
- Only *changes* in profits are shown (i.e. the difference between profit of case X and that of the Base case). Absolute profits are not shown, since they have no useful meaning.
- Profits are only accounted for the covered sectors.

Comments on Sectors' Profits:

- The cost of external GHG permits is provided separately in table II.19 for all sectors together. Note that the profits shown in table II.20 do not account for the cost of external GHG permits or the cost of internal CAC permits (the cost of permits may be computed for each sector only if and when the permit allowances have been defined for each sector).
- As is evident from table II.20, some sectors experience a profit *increase* at some periods. This is not a surprise, and results from two causes:
    - For some energy sectors, it may well happen that the *observed*[3] price elasticity of the demand for the commodity turns out to be less than 1. If that happens, the revenue from sales increase, even though production may decrease (this is the case of electricity and oil refining, for instance).
    - Even for some end-use industrial sectors (such as Chemicals), the profit actually increases when emission constraints are applied, even though the industry's output is reduced. This is explained by the combination of three factors: a) significant cost savings are induced by the reduction in output, b)

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[3] As already discussed, energy consumption is represented in detail in the model. Therefore, Alberta MARKAL does not rely on an exogenous elasticity for the energy commodities (except exports). Rather, the elasticity of demands for energy forms may be derived from the model results.

only the least profitable processes are abandoned by the model, and c) some emission reduction actions have negative costs (no regret actions).[4]

- For other sectors, profit decreases when constraints are applied. This is the case for two major energy sectors (natural gas and oil sands) and for the cement industry. Conventional oil falls somewhere in between, with profits decreasing in 2010 and 2015, but increasing in 2020.

Important remark: Of course, the non-covered sectors are expected to undergo significant reductions of their surpluses. For instance, residential and commercial heating and lighting are very little elastic to prices, and thus are bound to bear a portion of the overall burden of the emission reductions, in the form of increased heating and lighting bills. The same holds true for Transportation.

Table II.18. Total profit variations for covered sectors

Covered sectors M$/yr	2005	2010	2015	2020
2-GHG-Hg	70	223	257	313
3-LOW RED	70	223	255	309
4-MED RED	66	221	233	285
5-HIGH RED	69	207	184	61

Table II 19. Cost of external GHG permits for covered sectors (M$/yr)

Cost of external GHG permits	2005	2010	2015	2020
2-GHG-Hg	0	-32	27	280
3-LOW RED	0	-32	26	280
4-MED RED	0	-32	25	246
5-HIGH RED	0	-36	4	223

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[4] This is a good place to remind the reader that MARKAL computes only the direct financial costs and opportunity losses, but does not take into account other types of negative impacts such as: loss of market share, unemployment, shutdown costs, and the like.

Table II.20. Profit changes for each covered sector (M$/yr)

Oil conventional	2005	2010	2015	2020
2-GHG-Hg	-2	-15	-17	163
3-LOW RED	-2	-16	-19	169
4-MED RED	-2	-16	-22	159
5-HIGH RED	-2	-20	-33	149
Oil sands	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	5	-11	14	-69
3-LOW RED	5	-12	14	-69
4-MED RED	5	-12	19	-79
5-HIGH RED	5	-12	19	-249
Oil Refining	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	23	78	132	110
3-LOW RED	23	78	133	110
4-MED RED	22	79	135	118
5-HIGH RED	22	80	138	127
Gas upstream	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	27	-125	-77	-382
3-LOW RED	27	-126	-79	-394
4-MED RED	28	-128	-81	-446
5-HIGH RED	26	-137	-91	-474
EPG	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	9	206	59	336
3-LOW RED	9	210	59	337
4-MED RED	6	209	31	368
5-HIGH RED	9	207	-5	356
Chemicals	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	7	85	134	149
3-LOW RED	7	84	135	150
4-MED RED	6	84	138	158
5-HIGH RED	8	84	141	148
Cement	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	1	-2	0	-1
3-LOW RED	1	-2	0	-1
4-MED RED	1	-2	0	-2
5-HIGH RED	1	-2	0	-3
Pulp & Paper	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	0	7	12	7
3-LOW RED	0	7	12	7
4-MED RED	0	7	13	9
5-HIGH RED	0	7	15	7

only the least profitable processes are abandoned by the model, and c) some emission reduction actions have negative costs (no regret actions).[4]

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Important remark: Of course, the non-covered sectors are expected to undergo significant reductions of their surpluses. For instance, residential and commercial heating and lighting are very little elastic to prices, and thus are bound to bear a portion of the overall burden of the emission reductions, in the form of increased heating and lighting bills. The same holds true for Transportation.

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2-GHG-Hg	27	-125	-77	-382
3-LOW RED	27	-126	-79	-394
4-MED RED	28	-128	-81	-446
5-HIGH RED	26	-137	-91	-474
EPG	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	9	206	59	336
3-LOW RED	9	210	59	337
4-MED RED	6	209	31	368
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Chemicals	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	7	85	134	149
3-LOW RED	7	84	135	150
4-MED RED	6	84	138	158
5-HIGH RED	8	84	141	148
Cement	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	1	-2	0	-1
3-LOW RED	1	-2	0	-1
4-MED RED	1	-2	0	-2
5-HIGH RED	1	-2	0	-3
Pulp & Paper	**2005**	**2010**	**2015**	**2020**
2-GHG-Hg	0	7	12	7
3-LOW RED	0	7	12	7
4-MED RED	0	7	13	9
5-HIGH RED	0	7	15	7

2.7 Outputs

2.7.1 Oil and Gas

Table II.21 shows that oil and gas productions do not vary under the five cases. This was expected, in view of the relatively low marginal costs of the GHG and CAC constraints, and follows similar results obtained in previous analyses.

However, Alberta's oil and gas consumption does drop slightly in the constrained cases, and the saved oil and gas are exported instead of being consumed locally. Table II.22 shows the slight variations of exports, and table II.23 shows the small decrease in oil refinery throughput in the policy cases.

Table II.21. Oil and gas production under the five cases

PJ/yr		2000	2005	2010	2015	2020
1-BASE	oil sands	1588	3167	4822	5235	5235
1-BASE	oil conv	2132	2023	1934	1873	1700
1-BASE	gas	5695	6959	6785	6774	6730
2-GHG-Hg	oil sands	1581	3167	4822	5235	5235
2-GHG-Hg	oil conv	2132	2023	1934	1873	1700
2-GHG-Hg	gas	5695	6959	6785	6774	6730
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4-MED RED	oil conv	2132	2023	1934	1873	1700
4-MED RED	gas	5695	6959	6785	6774	6730
5-HIGH RED	oil sands	1582	3167	4822	5235	5235
5-HIGH RED	oil conv	2132	2023	1934	1873	1700
5-HIGH RED	gas	5695	6959	6785	6774	6730

Table II.22. Oil and Gas exports under the five cases

gas exports PJ/yr	2000	2005	2010	2015	2020
1-BASE	4710	5682	5406	5588	5840
2-GHG-Hg	4710	5697	5424	5617	5890
3-LOW RED	4710	5697	5424	5616	5890
4-MED RED	4710	5698	5425	5617	5865
5-HIGH RED	4710	5696	5423	5596	5848
oil exports PJ/yr	**2000**	**2005**	**2010**	**2015**	**2020**
1-BASE	2645	3951	5331	5290	5068
2-GHG-Hg	2645	3963	5357	5320	5099
3-LOW RED	2645	3963	5357	5320	5099
4-MED RED	2645	3961	5357	5320	5099
5-HIGH RED	2645	3962	5357	5320	5099

Table II.23. Oil refining throughput under the five cases

Mbbl/y	2000	2005	2010	2015	2020
1-BASE	162	151	154	190	196
2-GHG-Hg	161	149	150	185	191
3-LOW RED	161	149	150	185	191
4-MED RED	161	149	150	185	191
5-HIGH RED	161	149	150	185	191

2.7.2 Electricity Generation

The first observation is that total electricity production (table II.24) is negatively downward by the imposition of the GHG constraint (Case 2), but the additional constraints on CAC's do not further affect total generation. The decrease in generation from Case 1 to Case 2 is of the order of 10% at later periods.

Coal based generation is much more drastically affected than total generation, with a decline of 20% (relative to Base) in 2010 in Case 3, growing to 30% in 2020. Imposing CAC constraints induces a further decline in coal fired generation, which becomes 40% smaller in case 5 than in Base in 2020 (35.9 TWh vs. 58.6).

Gas based generation increases accordingly, reaching equality with coal based generation in case 5 at the end of the horizon.

We also note that the hardest hit are the new coal fired projects (Fording, Genesee, Keephills), which come in for 19 TWh in the Base case, but are reduced to only 2.9 TWh in that same year in Cases 2 to 5, barely enough for one of the five planned units. The competition of coal fired versus gas fired generation is better illustrated in Table II.25 showing the production by new units only. Gas captures between 80% and 90% of the new demand in the four constrained cases.

Finally, electricity from cogeneration is also stimulated by the reduction constraints, as shown in table II.26. The table shows cogeneration from industries, from commercial sector, and from municipalities. Industrial cogen is implemented in several industries, such as: Pulp and paper, Chemicals, and Oil sands.

2.7 Outputs

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5-HIGH RED	4710	5696	5423	5596	5848
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2-GHG-Hg	2645	3963	5357	5320	5099
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Table II.24. Electricity generation from three sectors (excluding DOW and Mildred

Electricity production TWh/yr		2000	2005	2010	2015	2020
1-BASE	ELE (BIO)	0.4	0	0	0.9	1.4
1-BASE	ELE (COAL)	44.1	46.5	55.6	59	58.6
1-BASE	ELE (GAS)	12.5	19.8	15.4	16.8	19.9
1-BASE	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
1-BASE	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
1-BASE	Total	**59.5**	**68.8**	**73.6**	**79.3**	**82.5**
2-GHG-Hg	ELE (BIO)	0.4	0	0.1	0.6	1.1
2-GHG-Hg	ELE (COAL)	44.1	45.2	43	42.6	42
2-GHG-Hg	ELE (GAS)	12.4	20.3	22.4	25.9	29.4
2-GHG-Hg	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
2-GHG-Hg	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
2-GHG-Hg	Total	**59.4**	**68.1**	**68**	**71.7**	**75.1**
3-LOW RED	ELE (BIO)	0.4	0	0.1	0.6	1.1
3-LOW RED	ELE (COAL)	44.1	45.2	43	42.5	42
3-LOW RED	ELE (GAS)	12.4	20.3	22.4	26.1	29.4
3-LOW RED	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
3-LOW RED	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
3-LOW RED	Total	**59.4**	**68.1**	**68**	**71.7**	**75.1**
4-MED RED	ELE (BIO)	0.3	0	0.1	0.5	1.1
4-MED RED	ELE (COAL)	44.1	45.2	43	42.5	38.4
4-MED RED	ELE (GAS)	12.4	20.3	22.4	26.2	33.5
4-MED RED	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
4-MED RED	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
4-MED RED	Total	**59.3**	**68.1**	**68**	**71.7**	**75.5**
5-HIGH RED	ELE (BIO)	0.1	0	0.1	0.5	1.3
5-HIGH RED	ELE (COAL)	44.1	44.9	42.7	39.5	35.9
5-HIGH RED	ELE (GAS)	12.7	20.6	22.8	29.4	35.9
5-HIGH RED	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
5-HIGH RED	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
5-HIGH RED	Total	**59.4**	**68.1**	**68**	**71.9**	**75.6**

Table II.25. New coal and New gas based electricity generation

New coal vs new gas		2005	2010	2015	2020
NEW COAL	1-BASE	4.1	15.1	19	19
TWh/yr	2-GHG-Hg	2.9	2.9	2.9	2.9
	3-LOW RED	2.9	2.9	2.9	2.9
	4-MED RED	2.9	2.9	2.9	2.9
	5-HIGH RED	2.6	2.6	2.6	2.6
NEW GAS	1-BASE	5.1	4.4	7.2	10.4
TWh/yr	2-GHG-Hg	6.3	12.7	16.4	19.9
	3-LOW RED	6.3	12.7	16.6	19.9
	4-MED RED	6.3	12.7	16.7	24.0
	5-HIGH RED	6.6	13.1	19.9	26.4

Table II.26. Cogeneration under the five cases

Cogeneration TWh		2000	2005	2010	2015	2020
1-BASE	Industrial Cogeneration	1.097	2.055	2.144	2.286	2.403
1-BASE	Total	**1.097**	**2.055**	**2.144**	**2.286**	**2.403**
2-GHG-Hg	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
2-GHG-Hg	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
2-GHG-Hg	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
2-GHG-Hg	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**
3-LOW RED	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
3-LOW RED	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
3-LOW RED	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
3-LOW RED	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**
4-MED RED	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
4-MED RED	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
4-MED RED	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
4-MED RED	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**
5-HIGH RED	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
5-HIGH RED	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
5-HIGH RED	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
5-HIGH RED	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**

2.7.3 Non-Energy Industrial Outputs

Table II.27 indicates how the annual growth rates of the non-energy industries are affected by the reduction targets. The first row of each sector's table indicates the Base case annual growth rates for the four 5 year periods. We provide these results for all non energy industries, including non-covered industries.

Generally speaking, the reduction scenarios induce very significant reductions in the growth rates of several industries. In all cases 2005-2010 is a period when all industries experience a marked slowdown, and sometimes a recession. In several cases, the next period 2010-2015 sees an improvement in the growth rates, although not back to the base case rates. In the last period, growth rates are often again close to the base case levels, although there are exceptions to this, such as Cement and Other Manufacturing, which stagnate in that period.

In spite of these drastic decreases in growth rates, we have seen in section 2.6 that profits may stagnate or even increase under the reduction policy cases. This is possible because it is the marginally profitable segments of each industry, which are shut down, whereas the remaining assets have a better profit margin.

Table II.27. Annual growth rates in end-use industries under the five cases

Table II.24. Electricity generation from three sectors (excluding DOW and Mildred

Electricity production TWh/yr		2000	2005	2010	2015	2020
1-BASE	ELE (BIO)	0.4	0	0	0.9	1.4
1-BASE	ELE (COAL)	44.1	46.5	55.6	59	58.6
1-BASE	ELE (GAS)	12.5	19.8	15.4	16.8	19.9
1-BASE	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
1-BASE	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
1-BASE	Total	59.5	68.8	73.6	79.3	82.5
2-GHG-Hg	ELE (BIO)	0.4	0	0.1	0.6	1.1
2-GHG-Hg	ELE (COAL)	44.1	45.2	43	42.6	42
2-GHG-Hg	ELE (GAS)	12.4	20.3	22.4	25.9	29.4
2-GHG-Hg	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
2-GHG-Hg	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
2-GHG-Hg	Total	59.4	68.1	68	71.7	75.1
3-LOW RED	ELE (BIO)	0.4	0	0.1	0.6	1.1
3-LOW RED	ELE (COAL)	44.1	45.2	43	42.5	42
3-LOW RED	ELE (GAS)	12.4	20.3	22.4	26.1	29.4
3-LOW RED	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
3-LOW RED	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
3-LOW RED	Total	59.4	68.1	68	71.7	75.1
4-MED RED	ELE (BIO)	0.3	0	0.1	0.5	1.1
4-MED RED	ELE (COAL)	44.1	45.2	43	42.5	38.4
4-MED RED	ELE (GAS)	12.4	20.3	22.4	26.2	33.5
4-MED RED	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
4-MED RED	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
4-MED RED	Total	59.3	68.1	68	71.7	75.5
5-HIGH RED	ELE (BIO)	0.1	0	0.1	0.5	1.3
5-HIGH RED	ELE (COAL)	44.1	44.9	42.7	39.5	35.9
5-HIGH RED	ELE (GAS)	12.7	20.6	22.8	29.4	35.9
5-HIGH RED	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
5-HIGH RED	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
5-HIGH RED	Total	59.4	68.1	68	71.9	75.6

Table II.25. New coal and New gas based electricity generation

New coal vs new gas		2005	2010	2015	2020
NEW COAL	1-BASE	4.1	15.1	19	19
TWh/yr	2-GHG-Hg	2.9	2.9	2.9	2.9
	3-LOW RED	2.9	2.9	2.9	2.9
	4-MED RED	2.9	2.9	2.9	2.9
	5-HIGH RED	2.6	2.6	2.6	2.6
NEW GAS	1-BASE	5.1	4.4	7.2	10.4
TWh/yr	2-GHG-Hg	6.3	12.7	16.4	19.9
	3-LOW RED	6.3	12.7	16.6	19.9
	4-MED RED	6.3	12.7	16.7	24.0
	5-HIGH RED	6.6	13.1	19.9	26.4

Table II.26. Cogeneration under the five cases

Cogeneration TWh/yr		2000	2005	2010	2015	2020
1-BASE	Industrial Cogeneration	1.097	2.055	2.144	2.286	2.403
1-BASE	Total	**1.097**	**2.055**	**2.144**	**2.286**	**2.403**
2-GHG-Hg	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
2-GHG-Hg	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
2-GHG-Hg	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
2-GHG-Hg	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**
3-LOW RED	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
3-LOW RED	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
3-LOW RED	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
3-LOW RED	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**
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4-MED RED	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**
5-HIGH RED	Commercial Cogeneration	0.06	0.531	1.002	1.504	2.005
5-HIGH RED	Industrial Cogeneration	1.175	2.632	2.515	2.501	2.543
5-HIGH RED	Land Fill - Municipality Action	0	0.014	0.071	0.071	0.071
5-HIGH RED	Total	**1.235**	**3.177**	**3.588**	**4.076**	**4.619**

2.7.3 Non-Energy Industrial Outputs

Table II.27 indicates how the annual growth rates of the non-energy industries are affected by the reduction targets. The first row of each sector's table indicates the Base case annual growth rates for the four 5 year periods. We provide these results for all non energy industries, including non-covered industries.

Generally speaking, the reduction scenarios induce very significant reductions in the growth rates of several industries. In all cases 2005-2010 is a period when all industries experience a marked slowdown, and sometimes a recession. In several cases, the next period 2010-2015 sees an improvement in the growth rates, although not back to the base case rates. In the last period, growth rates are often again close to the base case levels, although there are exceptions to this, such as Cement and Other Manufacturing, which stagnate in that period.

In spite of these drastic decreases in growth rates, we have seen in section 2.6 that profits may stagnate or even increase under the reduction policy cases. This is possible because it is the marginally profitable segments of each industry, which are shut down, whereas the remaining assets have a better profit margin.

Table II.27. Annual growth rates in end-use industries under the five cases

Annual sector growths under various cases					
Sector	**Scenario**	**2000-2005**	**2005-2010**	**2010-2015**	**2015-2020**
Mining	1-BASE	2.78%	1.98%	2.48%	2.54%
Mining	2-GHG-Hg	2.78%	0.61%	2.73%	2.78%
Mining	3-LOW RED	2.78%	0.61%	2.73%	2.78%
Mining	4-MED RED	2.78%	0.61%	2.73%	2.78%
Mining	5-HIGH RED	2.78%	0.61%	2.73%	2.78%
Chemicals	1-BASE	3.00%	2.72%	3.38%	2.76%
Chemicals	2-GHG-Hg	3.00%	-2.24%	0.39%	2.23%
Chemicals	3-LOW RED	3.00%	-2.24%	0.39%	2.23%
Chemicals	4-MED RED	3.00%	-2.24%	0.39%	2.23%
Chemicals	5-HIGH RED	3.00%	-2.24%	0.39%	2.23%
Cement	1-BASE	2.16%	1.29%	-0.29%	1.30%
Cement	2-GHG-Hg	-2.61%	-3.00%	-3.53%	0.00%
Cement	3-LOW RED	-2.61%	-3.00%	-3.53%	0.00%
Cement	4-MED RED	-2.61%	-3.00%	-3.53%	0.00%
Cement	5-HIGH RED	-2.61%	-3.00%	-3.53%	0.00%
Other Man	1-BASE	0.70%	0.57%	0.53%	0.52%
Other Man	2-GHG-Hg	0.51%	0.00%	0.00%	0.02%
Other Man	3-LOW RED	0.51%	0.00%	0.00%	0.02%
Other Man	4-MED RED	0.51%	0.00%	0.00%	0.02%
Other Man	5-HIGH RED	0.51%	0.00%	0.00%	0.02%
P&P	1-BASE	1.25%	1.24%	1.12%	1.15%
P&P	2-GHG-Hg	1.25%	-0.87%	-1.23%	1.15%
P&P	3-LOW RED	1.25%	-0.87%	-1.23%	1.15%
P&P	4-MED RED	1.25%	-0.87%	-1.23%	1.15%
P&P	5-HIGH RED	1.25%	-0.87%	-1.23%	1.15%

2.8 Conclusions

The results of running the five cases reported in this section were useful to arrive at a decision on three issues:

After due discussion of the results, it was decided to adopt the intermediate CAC targets for the policy runs of Cases 4a, 6, 7, and 8.

After examination of regional emissions it was decided not to impose special CAC emission constraints for any region.

The issue of banking was addressed. The runs discussed in Appendix A did not allow any banking. We also note that banking of GHG permits is a moot issue: there would be no economic advantage to so doing, since the value of GHG does not increase as fast as the discount rate. Banking of NOx and SOx has economic merit, since the prices of these two substances grow faster than the discount rate. On the other hand, allowing banking of

Annual sector growths under various cases					
Sector	Scenario	2000-2005	2005-2010	2010-2015	2015-2020
Mining	1-BASE	2.78%	1.98%	2.48%	2.54%
Mining	2-GHG-Hg	2.78%	0.61%	2.73%	2.78%
Mining	3-LOW RED	2.78%	0.61%	2.73%	2.78%
Mining	4-MED RED	2.78%	0.61%	2.73%	2.78%
Mining	5-HIGH RED	2.78%	0.61%	2.73%	2.78%
Chemicals	1-BASE	3.00%	2.72%	3.38%	2.76%
Chemicals	2-GHG-Hg	3.00%	-2.24%	0.39%	2.23%
Chemicals	3-LOW RED	3.00%	-2.24%	0.39%	2.23%
Chemicals	4-MED RED	3.00%	-2.24%	0.39%	2.23%
Chemicals	5-HIGH RED	3.00%	-2.24%	0.39%	2.23%
Cement	1-BASE	2.16%	1.29%	-0.29%	1.30%
Cement	2-GHG-Hg	-2.61%	-3.00%	-3.53%	0.00%
Cement	3-LOW RED	-2.61%	-3.00%	-3.53%	0.00%
Cement	4-MED RED	-2.61%	-3.00%	-3.53%	0.00%
Cement	5-HIGH RED	-2.61%	-3.00%	-3.53%	0.00%
Other Man	1-BASE	0.70%	0.57%	0.53%	0.52%
Other Man	2-GHG-Hg	0.51%	0.00%	0.00%	0.02%
Other Man	3-LOW RED	0.51%	0.00%	0.00%	0.02%
Other Man	4-MED RED	0.51%	0.00%	0.00%	0.02%
Other Man	5-HIGH RED	0.51%	0.00%	0.00%	0.02%
P&P	1-BASE	1.25%	1.24%	1.12%	1.15%
P&P	2-GHG-Hg	1.25%	-0.87%	-1.23%	1.15%
P&P	3-LOW RED	1.25%	-0.87%	-1.23%	1.15%
P&P	4-MED RED	1.25%	-0.87%	-1.23%	1.15%
P&P	5-HIGH RED	1.25%	-0.87%	-1.23%	1.15%

2.8 Conclusions

The results of running the five cases reported in this section were useful to arrive at a decision on three issues:

After due discussion of the results, it was decided to adopt the intermediate CAC targets for the policy runs of Cases 4a, 6, 7, and 8.

After examination of regional emissions it was decided not to impose special CAC emission constraints for any region.

The issue of banking was addressed. The runs discussed in Appendix A did not allow any banking. We also note that banking of GHG permits is a moot issue: there would be no economic advantage to so doing, since the value of GHG does not increase as fast as the discount rate. Banking of NOx and SOx has economic merit, since the prices of these two substances grow faster than the discount rate. On the other hand, allowing banking of

NOx and SOx may allow emissions in 2020 to be higher than environmentally desirable. It was decided to allow banking of these two substances but to limit the amounts banked to 50 kt/year for NOx and to a maximum of 75 kt/year for SOx. Reductions of both substances may be banked in 2010 for use in 2015 and 2020, and in 2015 for use in 2020. See sections 5.7 and 4.4 in the *Preliminary Analysis and Discussion Document*.

3. Policy Runs 4a, 6, and 7

After describing the three cases in section 3.1, 10 tables of results grouped in five sections are presented. These tables provide: total costs and emission prices, emissions (plus reductions and permit trading), outputs, profits, and electricity generation and prices.

3.1 Description of the Three Policy Cases

This part presents results from three runs, each using the same set of emission targets, (those of Case 4), the same assumptions on banking and/or trading of emissions, but different systems for the allocation of emission permits to each sector and subsector.

3.1.1 Emission Targets and Trading

- GHG emissions from the industrial sectors are collectively capped at 178 Mt/yr in 2010, 179 Mt/yr in 2015, and 158 Mt/yr in 2020. These caps represent imposed reductions of 16 Mt/yr, 30 Mt/yr, and 54 Mt/yr in 2010, 2015, and 2020 respectively. These caps were derived from the expected reduction in GHG intensity of Albetrta's industry as specified in the Alberta Action Plan on Climate Change. These sectors have access to a backstop reduction option costing \$10, \$14, and \$16.3 per tonne of CO_2 equivalent (expressed in 2000 C\$), in 2010, 2015, and 2020 respectively. Each sector may buy or sell permits at these prices in unlimited amounts. Let us remind the reader that industrial GHG emissions are modeled and capped for all industries, in contrast with the emissions of CAC's which are only modeled for covered industries.
- GHG emissions from the other sectors (transportation, residential, commercial, agriculture and landfills) are collectively capped at 56 Mt in 2010 and 2015, and at 60 Mt in 2020. These caps represent reductions of 4 Mt/yr, 5 Mt/yr, and 6 Mt/yr, in 2010, 2015, and 2020 respectively. These sectors may trade emissions between themselves, but may not trade emissions with the covered sectors or with an external market.
- NOx emissions from the covered sectors are capped at 577 kt/yr, 554 kt/yr, and 491 kt/yr in 2010, 2015 and 2020 respectively. The 2020 cap is equal to emissions in 2000. The 2010 and 2015 caps are obtained by interpolation of the reductions.
- SOx emissions from the covered sectors are collectively capped at 480 kt/yr, 427 kt/yr, and 350 kt/yr in 2010, 2015, and 2020 respectively. The 2020 cap is equal to 70% of emissions in year 2000. The 2010 and 2015 caps are obtained by interpolation of the reductions.

- Mercury emissions are capped at each source (i.e. each coal fired generation unit) separately. Each such unit must reduce its emissions by 50% (relative to its base case emissions) starting in 2010, and continuing until 2020. In order to reduce emissions, each unit may also use a generic reduction option costing $100,000 per kg of elemental mercury (expressed in 2000 C$).

3.1.2 Banking

- Banking of SOx and NOx reductions is allowed. NOx banking is limited to 50kt/year and banking of SOx is limited to 75 kt/year[5].
- Banking of GHG, although allowed in unlimited amounts, will not occur for economic reasons;
- Banking of mercury is not allowed.

3.1.3 Allocation Schemes

3.1.3.1 Case 4a (Option 2, See section 4.3 in Preliminary Analysis and Discussion Document)

Permits are allocated in a lump sum manner to each sector and subsector, proportionally to the (sub)sector's emissions in period 2000. The proportionality factor is chosen so as to respect the emission target.

Remark: it should be noted that case 4a may serve also to evaluate other lump sum allocation schemes. [it appears some additional words are needed to complete this sentence] For instance, full auction differs from case 4a only by the additional cost of permits purchased by each (sub)sector. Another scheme that has been simulated allocates permits so as to equalize the profit losses by the various (sub)sectors. The reader is referred to the main body of the *Preliminary Analysis and Discussion Document* for a discussion of these allocation methods.

3.1.3.2 Case 6 (option 3, See section 4.3 in Preliminary Analysis and Discussion Document)

In Case 6, CAC permits are allocated as in case 4a, but GHG permits are allocated to each (sub)sector proportionally to that (sub)sector's output in each future year. The proportionality factor is the same for all covered (sub)sectors, and is chosen so that the total allowance equals the target at each period. Because this allocation scheme depends on future outputs, it requires an iterative scheme for its simulation, as follows:

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[5] See sections 5.7 and 4.4 in the Main Summary Report

Step 1: assume a proportionality factor ***alpha(t)*** at each period (***t*** = 2010, 2015, 2020)
Step 2: run MARKAL assuming that each subsector receives an allocation of permits equal to: ***alpha(t) X {subsector's past intensity} X {subsector's output at period t}.***
Step 3: observe the resulting outputs and allocations. If the total allocation at each period is exactly equal to the target, STOP (the equilibrium has been reached). Otherwise, change ***alpha(t)*** and iterate on steps 2 and 3 until convergence is reached.

*3.1.3.3 Case 7 (option 4, See section 4.3 in **Preliminary Analysis and Discussion Document**)*

In Case 7, GHG permits and CAC permits are allocated proportionally to the output of each (sub)sector. The proportionality factors are selected so that the total allocation equals the target, for each pollutant and each period 2010, 2015, 2020. Finding the proportionality factors requires iterating as in Case 6. The general formula for the allocation of pollutant $\boldsymbol{p}$ to sector $\boldsymbol{s}$ at time period $\boldsymbol{t}$ is shown in (1) below, and the constraint of reaching the target is expressed by (2):

$$\boldsymbol{ALLOCATION_{s,p}(t) = alpha_p(t) \bullet INTENSITY_{s,p}(2000) \bullet OUTPUT_s(t)} \tag{1}$$

and

$$\boldsymbol{\sum_p ALLOCATION_{s,p}(t) = TARGET_p(t)} \tag{2}$$

Remark: a lump sum allocation of permits amounts to a windfall subsidy that is independent of production, and therefore has no impact on marginal production costs or on production decisions. In contrast, an output based allocation scheme provides a subsidy *per unit produced* and therefore has a direct impact on marginal costs of production. This is precisely the reason such schemes are effective at supporting production. This also explains why output depends on the allocation and conversely allocation depends on output, thus requiring the iterative scheme just described.

In the next five sections we present 10 tables, showing respectively: the loss of total surplus (table III.1), the shadow prices of the three pollutants (table III.2), the emissions by (sub)sector (table III.3), the reductions by (sub)sector (table III.4), the permit trading and/or banking by (sub)sector (table III.5), the outputs of each (sub)sector in physical units (table III.6), the emission intensities (table III.7), the profit changes by (sub)sector (table III.8), the electricity generation mix (table III.9), and the electricity prices (table III.10). Each table is followed by a set of brief comments.

3.2 Global Costs and Emission Prices

Table III.1. Loss of total surplus (costs) (1995 M$)

[illegible]	CASE 4a	CASE 6	CASE 7
External Permit Cost (GHG)	157	748	752
Technology Cost	-3784	-1363	-1360
Demand Loss	3725	981	978
Surplus Loss	**98**	**366**	**370**

Commentary

- Case 4a achieves a slightly lower overall surplus loss than the old case 4 (which was 110 M$), due to the increased efficiency of allowing permit banking
- Cases 6 and 7 show very nearly identical results, signalling that the main cost impact is brought by the output based GHG permit allocation, not by that of CAC permits
- In cases 6 and 7, demand losses are much smaller than in case 4a, but permit costs and system costs are both larger. The surplus loss although close to 4 times that of case 4a, remains modest. Note that total surplus ***must*** drop in Cases 6 and 7 relative to case 4a, since the latter represents a competitive market solution whereas the other two include a market distortion akin to a production subsidy per unit produced.

Table III.2. NOx and SOx Emission Prices (marginal reduction costs)

Emission prices $/t		2010	2015	2020
Case 4a	**NOx**	61	61	98
	SOx	136	218	218
case 6	**NOx**	61	98	158
	SOx	136	218	352
Case 7	**NOx**	61	98	158
	SOx	136	218	352

Commentary

- The main observation is that SOx and NOx prices in case 4a are much lower than those in old case 4, especially in 2020: the banking option functions! (as expected, when banking occurs, as for instance for NOx in 2015, the ratio of NOx prices in 2020 and 2015 is exactly equal to the discount factor for five years, i.e. 1.61. This is so because the role of banking is precisely to make the decision maker indifferent to

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	SOx	136	218	352

Commentary

- The main observation is that SOx and NOx prices in case 4a are much lower than those in old case 4, especially in 2020: the banking option functions! (as expected, when banking occurs, as for instance for NOx in 2015, the ratio of NOx prices in 2020 and 2015 is exactly equal to the discount factor for five years, i.e. 1.61. This is so because the role of banking is precisely to make the decision maker indifferent to reducing one additional tonne of pollutant in period T or to reducing that tonne in period T-1 and bank that tonne)

- Another point is that prices in Cases 6 and 7 are identical, and both larger than in Case 4a (as they must), although by a relatively moderate amount. We conclude that the distortion introduced by the output based allocations have a slight impact on the efficiency of CAC abatement strategies.

3.3 Emissions, Reductions, and Permit Trading and Banking

Three tables are presented, showing respectively the emissions of the various substances by each subsector at each time period (table III.3), the percent reductions relative to Base (table III.4), and the permit trading and banking levels (table III.5).

Table III.3. Emissions

Units: Mt per year for GHG. Kilotonnes per year for NOx and SOx emissions.

Mt/year	Base					Case 4a					Case 6					Case 7				
GHG	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	42	44.1	52.6	56.1	55.7	42	42.8	40.7	40.2	37.6	42	45.3	50.6	51.6	51.2	42	45.3	50.8	51.6	51.2
EPG gas	4.3	7.7	5.8	5.9	6.9	4.2	7.3	7.5	8.6	10.3	4.2	6.4	5.1	6.5	7.8	4.2	6.4	5.1	6.5	7.8
GAS	36.5	43.8	41	41.9	41.7	36.5	43.9	36.3	35.1	34.5	36.5	43.9	36.3	35.1	34.5	36.5	43.9	36.3	35.1	34.5
CHEMICALS	11.6	12.1	13.8	16.2	18.4	11.6	12.1	10.8	10.9	12.1	11.6	12.1	13.8	15.3	16.8	11.6	12.1	13.8	15.3	16.8
CEMENT	2.1	2	2.3	2.3	2.5	1.8	1.5	1.4	1.2	1.2	2.1	2	2	1.9	1.9	2.1	2	2	2	2
MINING	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.4	0.5	0.6	0.4	0.4	0.4	0.5	0.6	0.4	0.4	0.4	0.5	0.6
PAP	0.6	0.7	0.9	1	1.2	0.5	0.7	0.7	0.8	0.9	0.6	0.7	0.8	0.9	1	0.6	0.7	0.8	0.9	1
OTH INDUSTRY	4.7	5	5.3	5.6	5.6	4.6	4.8	4.8	5	5	4.6	4.8	4.8	4.8	4.6	4.6	4.8	4.8	4.8	4.6
CONV OIL	12	10.6	9.9	9.3	8.3	12	10.6	9.7	9.2	8.2	12	10.6	9.7	9.2	8.1	12	10.6	9.7	9.2	8.1
OIL REFINING	6.5	6	6.1	7.6	7.8	6.4	5.5	5.6	7	6.8	6.4	5.6	5.6	7	6.8	6.4	5.6	5.6	7	6.8
OIL SANDS	20.3	38	57.2	64.1	64.2	20.2	38	57.2	64.1	59.2	20.2	38	57.2	64.1	59.2	20.2	38	57.2	64.1	59.2
Total covered	140.9	170.6	195.3	210.6	213	140.3	167.8	175.2	182.6	176.4	140.5	169.9	186.4	196.9	192.8	140.5	169.9	186.6	196.9	192.8
NOx																				
CHEMICALS	14.4	16.7	19.1	22.6	25.9	14.4	16.7	13	13.2	14.4	14.4	16.7	16.6	18.1	20	14.4	16.7	16.6	18.1	20
CEMENT	4.8	5.4	5.7	5.6	6	4.8	4.2	3.6	3	3	4.8	5.4	5.2	4.7	4.7	4.8	5.4	5.2	4.8	4.8
PAP	3.8	4	4.3	4.5	4.8	3.8	4	3.9	3.6	3.9	3.8	4	4.3	4.1	4.3	3.8	4	4.3	4.1	4.3
EPG coal	81.6	83.3	93.1	97	96.9	81.6	81.8	66.9	65.6	58.9	81.6	84.8	77.9	77.4	72.9	81.6	84.8	78.1	77.4	72.9
EPG gas	6.8	11.5	5.3	3.7	4.3	6.7	10.2	4.9	5.4	6.6	6.7	8.1	2.9	3.9	4.8	6.7	8.2	2.9	3.9	4.8
GAS_ALL	249.7	315.6	317.7	327.6	336.2	249.7	315.6	281.8	205	203.9	249.7	315.7	246.5	195.5	204	249.7	315.7	246.1	195.4	204
CONV OIL	66.3	59.8	54.2	49.6	42.4	66.3	59.8	56.5	51.9	43.9	66.3	59.8	53.8	49.2	42	66.3	59.8	53.8	49.2	42
OIL REFINING	4.7	4.4	4.5	5.5	5.7	4.7	4.4	4.4	5.4	5.6	4.7	4.4	4.4	5.4	5.6	4.7	4.4	4.4	5.4	5.6
OIL SANDS	54	105.3	156.7	170.3	170.3	53.7	105.3	156.7	170.3	170.3	53.8	105.3	156.7	170.3	170.3	53.8	105.3	156.7	170.3	170.3
WOOD PROD	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7
Total covered	491.2	611.6	666.7	692.8	699.2	490.9	607.6	597.7	529.8	517.1	491	609.7	574.2	534.9	535.5	491	609.8	574	535	535.6
SOx																				
CEMENT	2.9	3.2	3.4	3.3	3.6	2.9	2.5	2.2	1.5	1.5	2.9	3.2	3.1	2.4	2.4	2.9	3.2	3.1	2.4	2.4
PAP	2	2.2	2.3	2.4	2.6	2	2.2	2.1	1.9	2.1	2	2.2	2.3	2.2	2.3	2	2.2	2.3	2.2	2.3
EPG coal	128.1	126	129.3	135	135	128.1	123.8	116.4	114.5	104.1	128.1	128.2	126	127	127	128.1	128.2	126	127	127
EPG gas	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.02
GAS_ALL	227.5	216.4	210.9	210.4	208.9	227.5	216.4	143	125.2	52	227.5	216.4	143	86.1	45.4	227.5	216.4	143	86	45.4
CONV OIL	32.4	19.4	18.5	18	16.3	32.4	19.4	18.5	17.9	16.3	32.4	19.4	18.5	17.9	16.3	32.4	19.4	18.5	17.9	16.3
OIL REFINING	13.1	12.2	12.4	15.4	15.8	13	12.1	12.1	9.8	10.1	13	12.1	12.2	9.8	7.4	13	12.1	12.2	9.8	7.4
OIL SANDS	94	116.9	168.7	173.7	164	93.6	116.9	168.7	173.7	164	93.7	116.9	168.7	173.7	164	93.7	116.9	168.7	173.7	164
Total covered	500	496.4	545.6	558.2	546.2	499.6	493.3	463	444.6	350	499.7	498.4	473.7	419.1	364.7	499.7	498.4	473.8	419	364.8

Table III.3. Emissions

Units: Mt per year for GHG. Kilotonnes per year for NOx and SOx emissions.

Mt/year	Base					Case 4a					Case 6					Case 7				
GHG	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	42	44.1	52.6	56.1	55.7	42	42.8	40.7	40.2	37.6	42	45.3	50.6	51.6	51.2	42	45.3	50.8	51.6	51.2
EPG gas	4.3	7.7	5.8	5.9	6.9	4.2	7.3	7.5	8.6	10.3	4.2	6.4	5.1	6.5	7.8	4.2	6.4	5.1	6.5	7.8
GAS	36.5	43.8	41	41.9	41.7	36.5	43.9	36.3	35.1	34.5	36.5	43.9	36.3	35.1	34.5	36.5	43.9	36.3	35.1	34.5
CHEMICALS	11.6	12.1	13.8	16.2	18.4	11.6	12.1	10.8	10.9	12.1	11.6	12.1	13.8	15.3	16.8	11.6	12.1	13.8	15.3	16.8
CEMENT	2.1	2	2.3	2.3	2.5	1.8	1.5	1.4	1.2	1.2	2.1	2	2	1.9	1.9	2.1	2	2	2	2
MINING	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.4	0.5	0.6	0.4	0.4	0.4	0.5	0.6	0.4	0.4	0.4	0.5	0.6
PAP	0.6	0.7	0.9	1	1.2	0.5	0.7	0.7	0.8	0.9	0.6	0.7	0.8	0.9	1	0.6	0.7	0.8	0.9	1
OTH INDUSTRY	4.7	5	5.3	5.6	5.6	4.6	4.8	4.8	5	5	4.6	4.8	4.8	4.8	4.6	4.6	4.8	4.8	4.8	4.6
CONV OIL	12	10.6	9.9	9.3	8.3	12	10.6	9.7	9.2	8.2	12	10.6	9.7	9.2	8.1	12	10.6	9.7	9.2	8.1
OIL REFINING	6.5	6	6.1	7.6	7.8	6.4	5.5	5.6	7	6.8	6.4	5.6	5.6	7	6.8	6.4	5.6	5.6	7	6.8
OIL SANDS	20.3	38	57.2	64.1	64.2	20.2	38	57.2	64.1	59.2	20.2	38	57.2	64.1	59.2	20.2	38	57.2	64.1	59.2
Total covered	140.9	170.6	195.3	210.6	213	140.3	167.8	175.2	182.6	176.4	140.5	169.9	186.4	196.9	192.8	140.5	169.9	186.6	196.9	192.8
NOx																				
CHEMICALS	14.4	16.7	19.1	22.6	25.9	14.4	16.7	13	13.2	14.4	14.4	16.7	16.6	18.1	20	14.4	16.7	16.6	18.1	20
CEMENT	4.8	5.4	5.7	5.6	6	4.8	4.2	3.6	3	3	4.8	5.4	5.2	4.7	4.7	4.8	5.4	5.2	4.8	4.8
PAP	3.8	4	4.3	4.5	4.8	3.8	4	3.9	3.6	3.9	3.8	4	4.3	4.1	4.3	3.8	4	4.3	4.1	4.3
EPG coal	81.6	83.3	93.1	97	96.9	81.6	81.8	66.9	65.6	58.9	81.6	84.8	77.9	77.4	72.9	81.6	84.8	78.1	77.4	72.9
EPG gas	6.8	11.5	5.3	3.7	4.3	6.7	10.2	4.9	5.4	6.6	6.7	8.1	2.9	3.9	4.8	6.7	8.2	2.9	3.9	4.8
GAS_ALL	249.7	315.6	317.7	327.6	336.2	249.7	315.6	281.8	205	203.9	249.7	315.7	246.5	195.5	204	249.7	315.7	246.1	195.4	204
CONV OIL	66.3	59.8	54.2	49.6	42.4	66.3	59.8	56.5	51.9	43.9	66.3	59.8	53.8	49.2	42	66.3	59.8	53.8	49.2	42
OIL REFINING	4.7	4.4	4.5	5.5	5.7	4.7	4.4	4.4	5.4	5.6	4.7	4.4	4.4	5.4	5.6	4.7	4.4	4.4	5.4	5.6
OIL SANDS	54	105.3	156.7	170.3	170.3	53.7	105.3	156.7	170.3	170.3	53.8	105.3	156.7	170.3	170.3	53.8	105.3	156.7	170.3	170.3
WOOD PROD	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7
Total covered	491.2	611.6	666.7	692.8	699.2	490.9	607.6	597.7	529.8	517.1	491	609.7	574.2	534.9	535.5	491	609.8	574	535	535.6
SOx																				
CEMENT	2.9	3.2	3.4	3.3	3.6	2.9	2.5	2.2	1.5	1.5	2.9	3.2	3.1	2.4	2.4	2.9	3.2	3.1	2.4	2.4
PAP	2	2.2	2.3	2.4	2.6	2	2.2	2.1	1.9	2.1	2	2.2	2.3	2.2	2.3	2	2.2	2.3	2.2	2.3
EPG coal	128.1	126	129.3	135	135	128.1	123.8	116.4	114.5	104.1	128.1	128.2	126	127	127	128.1	128.2	126	127	127
EPG gas	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.02
GAS_ALL	227.5	216.4	210.9	210.4	208.9	227.5	216.4	143	125.2	52	227.5	216.4	143	86.1	45.4	227.5	216.4	143	86	45.4
CONV OIL	32.4	19.4	18.5	18	16.3	32.4	19.4	18.5	17.9	16.3	32.4	19.4	18.5	17.9	16.3	32.4	19.4	18.5	17.9	16.3
OIL REFINING	13.1	12.2	12.4	15.4	15.8	13	12.1	12.1	9.8	10.1	13	12.1	12.2	9.8	7.4	13	12.1	12.2	9.8	7.4
OIL SANDS	94	116.9	168.7	173.7	164	93.6	116.9	168.7	173.7	164	93.7	116.9	168.7	173.7	164	93.7	116.9	168.7	173.7	164
Total covered	500	496.4	545.6	558.2	546.2	499.6	493.3	463	444.6	350	499.7	498.4	473.7	419.1	364.7	499.7	498.4	473.8	419	364.8

Table III.4. Reductions relative to Base

GHG reductions relative to to BASE CASE				Case 4a				Case 6					Case 7				
					2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal		GHG	0%	-3%	-23%	-28%	-32%	0%	3%	-4%	-8%	-8%	0%	3%	-3%	-8%	-8%
EPG gas			-2%	-5%	30%	44%	48%	-3%	-16%	-11%	9%	13%	-3%	-16%	-11%	9%	13%
GAS			0%	0%	-12%	-16%	-17%	0%	0%	-12%	-16%	-17%	0%	0%	-12%	-16%	-17%
CHEMICALS			0%	0%	-22%	-32%	-34%	0%	0%	0%	-5%	-9%	0%	0%	0%	-5%	-9%
CEMENT			0%	-24%	-39%	-47%	-50%	0%	0%	-11%	-17%	-22%	0%	0%	-11%	-15%	-21%
MINING			0%	0%	-7%	-6%	-4%	0%	0%	-7%	-6%	-4%	0%	0%	-7%	-6%	-4%
P&P			0%	-6%	-16%	-25%	-23%	-7%	-6%	-5%	-14%	-13%	-7%	-6%	-5%	-14%	-13%
OTH INDUSTRY			-2%	-3%	-8%	-11%	-11%	-2%	-3%	-9%	-14%	-18%	-2%	-3%	-9%	-14%	-18%
CONV OIL			0%	0%	-2%	-2%	-2%	0%	0%	-2%	-2%	-2%	0%	0%	-2%	-2%	-2%
OIL REFINING			-1%	-8%	-10%	-8%	-14%	0%	-8%	-9%	-8%	-13%	0%	-8%	-9%	-8%	-13%
OIL SANDS			0%	0%	0%	0%	-8%	0%	0%	0%	0%	-8%	0%	0%	0%	0%	-8%
Total covered			**0%**	**-2%**	**-10%**	**-13%**	**-17%**	**0%**	**0%**	**-5%**	**-7%**	**-10%**	**0%**	**0%**	**-4%**	**-7%**	**-9%**
CHEMICALS		NOx	0%	0%	-32%	-41%	-44%	0%	0%	-13%	-20%	-22%	0%	0%	-13%	-20%	-22%
CEMENT			0%	-21%	-37%	-46%	-50%	0%	0%	-10%	-16%	-22%	0%	0%	-10%	-15%	-20%
P&P			0%	0%	-10%	-20%	-20%	0%	0%	0%	-10%	-10%	0%	0%	0%	-10%	-10%
EPG coal			0%	-2%	-28%	-32%	-39%	0%	2%	-16%	-20%	-25%	0%	2%	-16%	-20%	-25%
EPG gas			-1%	-11%	-7%	46%	55%	-1%	-30%	-46%	6%	13%	-1%	-29%	-46%	6%	14%
GAS_ALL			0%	0%	-11%	-37%	-39%	0%	0%	-22%	-40%	-39%	0%	0%	-23%	-40%	-39%
CONV OIL			0%	0%	4%	5%	4%	0%	0%	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%
OIL REFINING			-1%	-1%	-3%	-3%	-3%	0%	-1%	-2%	-2%	-2%	0%	-1%	-2%	-2%	-2%
OIL SANDS			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WOOD PROD			0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered			**0%**	**-1%**	**-10%**	**-24%**	**-26%**	**0%**	**0%**	**-14%**	**-23%**	**-23%**	**0%**	**0%**	**-14%**	**-23%**	**-23%**

Table III.4. Reductions relative to Base

GHG reductions relative to to BASE CASE			Case 4a				Case 6					Case 7				
				2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
CEMENT	SOx	0%	-21%	-37%	-54%	-57%	0%	0%	-10%	-28%	-33%	0%	0%	-10%	-27%	-31%
P&P		0%	0%	-10%	-20%	-20%	0%	0%	0%	-10%	-10%	0%	0%	0%	-10%	-10%
EPG coal		0%	-2%	-10%	-15%	-23%	0%	2%	-3%	-6%	-6%	0%	2%	-3%	-6%	-6%
EPG gas		-1%	1%	18%	63%	66%	-2%	-3%	-38%	9%	14%	-2%	-3%	-38%	9%	14%
GAS_ALL		0%	0%	-32%	-41%	-75%	0%	0%	-32%	-59%	-78%	0%	0%	-32%	-59%	-78%
CONV OIL		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OIL REFINING		-1%	-1%	-3%	-36%	-36%	0%	-1%	-2%	-36%	-54%	0%	-1%	-2%	-36%	-54%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		0%	-1%	-15%	-20%	-36%	0%	0%	-13%	-25%	-33%	0%	0%	-13%	-25%	-33%

Commentary

- Oil Sands effect little GHG reduction and no CAC reductions over all three allocation schemes.
- In general, cases 6 and 7 provoke less GHG reductions than case 4a (and of course more permit purchases, as will be seen below)
- EPG-coal, Chemicals, Cement, and pulp & paper effect less GHG reductions in Cases 6-7 than 4a
- EPG-Gas effects more reductions (because its output is less)
- The other sectors effect the same reductions in all three cases.

Table III.4. Reductions relative to Base

GHG reductions relative to to BASE CASE			Case 4a				Case 6					Case 7				
				2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	GHG	0%	-3%	-23%	-28%	-32%	0%	3%	-4%	-8%	-8%	0%	3%	-3%	-8%	-8%
EPG gas		-2%	-5%	30%	44%	48%	-3%	-16%	-11%	9%	13%	-3%	-16%	-11%	9%	13%
GAS		0%	0%	-12%	-16%	-17%	0%	0%	-12%	-16%	-17%	0%	0%	-12%	-16%	-17%
CHEMICALS		0%	0%	-22%	-32%	-34%	0%	0%	0%	-5%	-9%	0%	0%	0%	-5%	-9%
CEMENT		0%	-24%	-39%	-47%	-50%	0%	0%	-11%	-17%	-22%	0%	0%	-11%	-15%	-21%
MINING		0%	0%	-7%	-6%	-4%	0%	0%	-7%	-6%	-4%	0%	0%	-7%	-6%	-4%
P&P		0%	-6%	-16%	-25%	-23%	-7%	-6%	-5%	-14%	-13%	-7%	-6%	-5%	-14%	-13%
OTH INDUSTRY		-2%	-3%	-8%	-11%	-11%	-2%	-3%	-9%	14%	-18%	-2%	-3%	-9%	-14%	-18%
CONV OIL		0%	0%	-2%	-2%	-2%	0%	0%	-2%	-2%	-2%	0%	0%	-2%	-2%	-2%
OIL REFINING		-1%	-8%	-10%	-8%	-14%	0%	-8%	-9%	-8%	-13%	0%	-8%	-9%	-8%	-13%
OIL SANDS		0%	0%	0%	0%	-6%	0%	0%	0%	0%	-8%	0%	0%	0%	0%	-6%
Total covered		**0%**	**-2%**	**-10%**	**-13%**	**-17%**	**0%**	**0%**	**-5%**	**-7%**	**-10%**	**0%**	**0%**	**-4%**	**-7%**	**-9%**
CHEMICALS	NOx	0%	0%	-32%	-41%	-44%	0%	0%	-13%	-20%	-22%	0%	0%	-13%	-20%	-22%
CEMENT		0%	-21%	-37%	-46%	-50%	0%	0%	-10%	-16%	-22%	0%	0%	-10%	-15%	-20%
P&P		0%	0%	-10%	20%	-20%	0%	0%	0%	-10%	-10%	0%	0%	0%	-10%	-10%
EPG coal		0%	-2%	-28%	-32%	-39%	0%	2%	-16%	-20%	-25%	0%	2%	-16%	-20%	-25%
EPG gas		-1%	-11%	7%	46%	55%	-1%	-30%	-46%	6%	13%	-1%	-29%	-46%	6%	14%
GAS_ALL		0%	0%	-11%	-37%	-39%	0%	0%	-22%	-40%	-39%	0%	0%	-23%	-40%	-39%
CONV OIL		0%	0%	4%	5%	4%	0%	0%	-1%	-1%	-1%	0%	0%	-1%	-1%	-1%
OIL REFINING		-1%	-1%	-3%	-3%	-3%	0%	-1%	-2%	-2%	-2%	0%	-1%	-2%	-2%	-2%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WOOD PROD		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		0%	-1%	-10%	-24%	-26%	0%	0%	-14%	-23%	-23%	0%	0%	-14%	-23%	-23%

Table III.4. Reductions relative to Base

GHG reductions relative to to BASE CASE			Case 4a				Case 6					Case 7				
			[illegible]	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
CEMENT	SOx	0%	-21%	-37%	-54%	-57%	0%	0%	-10%	-28%	-33%	0%	0%	-10%	-27%	-31%
P&P		0%	0%	-10%	-20%	-20%	0%	0%	0%	-10%	-10%	0%	0%	0%	-10%	-10%
EPG coal		0%	-2%	-10%	-15%	-23%	0%	2%	-3%	-6%	-6%	0%	2%	-3%	-6%	-6%
EPG gas		-1%	1%	18%	63%	66%	-2%	-3%	-38%	9%	14%	-2%	-3%	-38%	9%	14%
GAS_ALL		0%	0%	-32%	-41%	-75%	0%	0%	-32%	-59%	-78%	0%	0%	-32%	-59%	-78%
CONV OIL		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OIL REFINING		-1%	-1%	-3%	-36%	-36%	0%	-1%	-2%	-36%	-54%	0%	-1%	-2%	-36%	-54%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		0%	-1%	-15%	-20%	-36%	0%	0%	-13%	-25%	-33%	0%	0%	-13%	-25%	-33%

Commentary

- Oil Sands effect little GHG reduction and no CAC reductions over all three allocation schemes.
- In general, cases 6 and 7 provoke less GHG reductions than case 4a (and of course more permit purchases, as will be seen below)
- EPG-coal, Chemicals, Cement, and pulp & paper effect less GHG reductions in Cases 6-7 than 4a
- EPG-Gas effects more reductions (because its output is less)
- The other sectors effect the same reductions in all three cases.

Table III.5. Permit trading and banking

		Case 4a				Case 6				Case 7			
Permit purchases		2010	2015	2020		2010	2015	2020		2010	2015	2020	
EPG coal	GHG	-12.3	-13.3	-9.5	Sell	6.5	8.5	14.0	Buy	6.3	8.3	13.7	Buy
EPG gas	Mt/yr	2.1	3.0	5.4	Buy	0.5	0.7	1.6	Buy	0.5	0.6	1.6	Buy
GAS		-9.7	-11.3	-6.4	Sell	-1.2	-0.8	3.4	Sell,buy	-1.4	-1.0	3.2	Sell,buy
CHEMICALS		-3.8	-3.8	-0.8	Buy	0.5	1.1	3.2	Buy	0.5	1.0	3.1	Buy
CEMENT		-1.3	-1.5	-1.1	Sell	0.1	0.2	0.4	Buy	0.1	0.2	0.4	Buy
MINING		0.0	0.1	0.2	Buy	0.0	0.1	0.2	Buy	0.0	0.1	0.2	Buy
P&P		0.0	0.0	0.2	Buy	0.3	0.4	0.5	Buy	0.3	0.3	0.5	Buy
OTH INDUSTRY		-1.1	-1.0	-0.3	Sell	-1.2	-1.2	-0.6	Sell	-1.2	-1.2	-0.6	Sell
CONV OIL		-5.5	-6.1	-5.3	Sell	0.9	1.0	1.7	Buy	0.3	0.4	1.2	Buy
OIL REFINING		-2.6	-1.3	-0.5	Sell	0.4	0.9	1.3	Buy	0.4	0.8	1.2	Buy
OIL SANDS		31.6	38.3	36.5	Buy	1.7	6.5	9.1	Buy	3.3	8.0	10.4	Buy
Total covered		**-2.6**	**3.2**	**18.5**	**Sell,buy**	**8.5**	**17.3**	**34.8**	**Buy**	**8.8**	**17.5**	**34.9**	**Buy**
CHEMICALS	NOx	-4.6	-3.1	0.0	Sell	-0.9	1.8	5.6	Bank,buy	-0.4	0.9	3.1	Bank,buy
CEMENT	kt/yr	-2.2	-2.4	-1.8	Sell	-0.7	-0.7	-0.1	Sell	0.6	0.9	1.4	Buy
P&P		-0.8	-0.7	0.1	Sell,buy	-0.3	-0.2	0.5	Bank	0.5	0.8	1.2	Buy
EPG coal		-32.5	-26.7	-22.8	Sell	-21.4	-15.0	-8.7	Sell	-10.6	-4.1	1.0	Bank, Sell
EPG gas		-3.3	-2.3	-0.2	Sell	-5.4	-3.8	-2.0	Sell	-4.6	-5.0	-4.8	Sell
GAS_ALL		-22.0	-77.5	-45.7	Sell	-57.3	-87.0	-45.7	Sell	-18.6	-43.8	-7.4	Sell
CONV OIL		-24.1	-23.0	-22.4	Sell	-26.8	-25.7	-24.2	Sell	0.4	2.3	4.2	Buy
OIL REFINING		-1.4	0.1	0.8	Sell, buy	-1.4	0.1	0.9	Bank, sell	0.5	1.1	1.6	Buy
OIL SANDS		91.1	109.2	116.3	Buy	91.1	109.2	116.3	Buy	9.5	25.8	41.8	Buy
WOOD PROD		-0.3	0.5	1.6	Bank,buy	-0.3	0.5	1.6	Bank, buy	-0.3	0.5	1.6	Bank, buy
Total covered		**0.00**	**-25.94**	**25.93**	**Bank in 2015**	**-23.47**	**-20.85**	**44.25**	**Bank**	**-23.1**	**-20.4**	**43.7**	**Bank**

Table III.5. Permit trading and banking

permit purchases		Case 4a				Case 6				Case 7			
		2010	2015	2020		2010	2015	2020		2010	2015	2020	
CEMENT	SOx	-0.6	-0.9	-0.5	Sell	0.3	0.0	0.4	Buy	1.1	0.9	1.2	Buy
P&P	kt/yr	0.1	0.2	0.6	Buy	0.3	0.5	0.9	Buy	0.9	1.0	1.3	Buy
EPG coal		-6.6	5.0	14.4	Bank, buy	3.0	17.5	37.3	Buy	27.5	41.1	56.8	Buy
EPG gas		0.0	0.0	0.0	--	0.0	0.0	0.0	--	0.0	0.0	0.0	--
GAS_ALL		-75.5	-69.3	-107.3	Sell	-75.5	-108.3	-113.8	Sell	-27.7	-60.4	-74.4	Sell
CONV OIL		-12.7	-9.8	-6.4	Sell	-12.7	-9.8	-6.4	Sell	0.0	2.5	4.7	Buy
OIL REFINING		-0.5	-1.4	0.9	Bank, sell	-0.4	-1.3	-1.8	Sell	4.5	1.7	0.4	Buy
OIL SANDS		78.5	93.3	98.2	Buy	78.5	93.3	98.2	Buy	-12.7	4.7	24.7	Bank, buy
Total covered		**-17.22**	**17.21**	**0.00**	**bank**	**-6.46**	**-8.26**	**14.72**	**bank**	**-6.5**	**-8.5**	**14.7**	**bank**

Commentary

- Industry as a whole buys a moderate amount of GHG permits in case 4a, but more than doubles its purchases in cases 6 and 7, because the output based allocation allows outputs to be maintained (as discussed below), thus entailing more emissions in several sectors. In cases 6 and 7, almost every sector buys GHG permits from the external market, and Alberta fulfills 65% of reductions via external permits.
- In Case 4a, oil sands is a big buyer of permits for all three substances, whereas most other sectors sell (or bank) CAC permits. Gas and EPG-coal are the largest sellers of permits. In Case 6, Oil sands buys much less GHG permits because its rapid output growth commands a generous allocation of permits; however, the sector still buys large amounts of NOx and SOx permits from the EPG-coal, Gas, and conventional oil sectors. In case 7, Oil sands buys much smaller amounts of NOx and SOx permits –which are now allocated based on output, and banks a fairly large amount in 2010. The main supplier of permits is the Gas sector. Other sectors are either modest sellers or buyers, but EPG-coal sells NOx permits and buys SOx permits.
- Overall, the trading of NOx and SOx is less intense in case 7 than in any other case, as one would expect from an output-based allocation scheme. However, total trading and/or banking remain strong.

Table III.5. Permit trading and banking

		Case 4a				Case 6				Case 7			
permit purchases		2010	2015	2020		2010	2015	2020		2010	2015	2020	
EPG coal	GHG	-12.3	-13.3	-9.5	Sell	6.5	8.5	14.0	Buy	6.3	8.3	13.7	Buy
EPG gas	Mt/yr	2.1	3.0	5.4	Buy	0.5	0.7	1.6	Buy	0.5	0.6	1.6	Buy
GAS		-9.7	-11.3	-6.4	Sell	-1.2	-0.8	3.4	Sell,buy	-1.4	-1.0	3.2	Sell,buy
CHEMICALS		-3.8	-3.8	-0.8	Buy	0.5	1.1	3.2	Buy	0.5	1.0	3.1	Buy
CEMENT		-1.3	-1.5	-1.1	Sell	0.1	0.2	0.4	Buy	0.1	0.2	0.4	Buy
MINING		0.0	0.1	0.2	Buy	0.0	0.1	0.2	Buy	0.0	0.1	0.2	Buy
P&P		0.0	0.0	0.2	Buy	0.3	0.4	0.5	Buy	0.3	0.3	0.5	Buy
OTH INDUSTRY		-1.1	-1.0	-0.3	Sell	-1.2	-1.2	-0.6	Sell	-1.2	-1.2	-0.6	Sell
CONV OIL		-5.5	-6.1	-5.3	Sell	0.9	1.0	1.7	Buy	0.3	0.4	1.2	Buy
OIL REFINING		-2.6	-1.3	-0.5	Sell	0.4	0.9	1.3	Buy	0.4	0.8	1.2	Buy
OIL SANDS		31.6	38.3	36.5	Buy	1.7	6.5	9.1	Buy	3.3	8.0	10.4	Buy
Total covered		**-2.6**	**3.2**	**18.5**	**Sell,buy**	**8.5**	**17.3**	**34.8**	**Buy**	**8.8**	**17.5**	**34.9**	**Buy**
CHEMICALS	NOx	-4.6	-3.1	0.0	Sell	-0.9	1.8	5.6	Bank,buy	-0.4	0.9	3.1	Bank,buy
CEMENT	kt/yr	-2.2	-2.4	-1.8	Sell	-0.7	-0.7	-0.1	Sell	0.6	0.9	1.4	Buy
P&P		-0.8	-0.7	0.1	Sell,buy	-0.3	-0.2	0.5	Bank	0.5	0.8	1.2	Buy
EPG coal		-32.5	-26.7	-22.8	Sell	-21.4	-15.0	-8.7	Sell	-10.6	-4.1	1.0	Bank, Sell
EPG gas		-3.3	-2.3	-0.2	Sell	-5.4	-3.8	-2.0	Sell	-4.6	-5.0	-4.8	Sell
GAS_ALL		-22.0	-77.5	-45.7	Sell	-57.3	-87.0	-45.7	Sell	-18.6	-43.8	-7.4	Sell
CONV OIL		-24.1	-23.0	-22.4	Sell	-26.8	-25.7	-24.2	Sell	0.4	2.3	4.2	Buy
OIL REFINING		-1.4	0.1	0.8	Sell, buy	-1.4	0.1	0.9	Bank, sell	0.5	1.1	1.6	Buy
OIL SANDS		91.1	109.2	116.3	Buy	91.1	109.2	116.3	Buy	9.5	25.8	41.8	Buy
WOOD PROD		-0.3	0.5	1.6	Bank,buy	-0.3	0.5	1.6	Bank, buy	-0.3	0.5	1.6	Bank, buy
Total covered		**0.00**	**-25.94**	25.93	**Bank in 2015**	**-23.47**	**-20.85**	**44.25**	**Bank**	**-23.1**	**-20.4**	**43.7**	**Bank**

Table III.5. Permit trading and banking

		Case 4a				Case 6				Case 7			
permit purchases		2010	2015	2020		2010	2015	2020		2010	2015	2020	
CEMENT	SOx	-0.6	-0.9	-0.5	Sell	0.3	0.0	0.4	Buy	1.1	0.9	1.2	Buy
P&P	kt/yr	0.1	0.2	0.6	Buy	0.3	0.5	0.9	Buy	0.9	1.0	1.3	Buy
EPG coal		-6.6	5.0	14.4	Bank, buy	3.0	17.5	37.3	Buy	27.5	41.1	56.8	Buy
EPG gas		0.0	0.0	0.0	--	0.0	0.0	0.0	--	0.0	0.0	0.0	--
GAS_ALL		-75.5	-69.3	-107.3	Sell	-75.5	-108.3	-113.8	Sell	-27.7	-60.4	-74.4	Sell
CONV OIL		-12.7	-9.8	-6.4	Sell	-12.7	-9.8	-6.4	Sell	0.0	2.5	4.7	Buy
OIL REFINING		-0.5	-1.4	0.9	Bank, sell	-0.4	-1.3	-1.8	Sell	4.5	1.7	0.4	Buy
OIL SANDS		78.5	93.3	98.2	Buy	78.5	93.3	98.2	Buy	-12.7	4.7	24.7	Bank, buy
Total covered		**-17.22**	**17.21**	**0.00**	**bank**	**-6.46**	**-8.26**	**14.72**	**bank**	**-6.5**	**-8.5**	**14.7**	**bank**

Commentary

- Industry as a whole buys a moderate amount of GHG permits in case 4a, but more than doubles its purchases in cases 6 and 7, because the output based allocation allows outputs to be maintained (as discussed below), thus entailing more emissions in several sectors. In cases 6 and 7, almost every sector buys GHG permits from the external market, and Alberta fulfills 65% of reductions via external permits.
- In Case 4a, oil sands is a big buyer of permits for all three substances, whereas most other sectors sell (or bank) CAC permits. Gas and EPG-coal are the largest sellers of permits. In Case 6, Oil sands buys much less GHG permits because its rapid output growth commands a generous allocation of permits; however, the sector still buys large amounts of NOx and SOx permits from the EPG-coal, Gas, and conventional oil sectors. In case 7, Oil sands buys much smaller amounts of NOx and SOx permits – which are now allocated based on output, and banks a fairly large amount in 2010. The main supplier of permits is the Gas sector. Other sectors are either modest sellers or buyers, but EPG-coal sells NOx permits and buys SOx permits.
- Overall, the trading of NOx and SOx is less intense in case 7 than in any other case, as one would expect from an output-based allocation scheme. However, total trading and/or banking remain strong.

3.4 Outputs and Emission Intensities

Outputs are an important class of results, since one of the main reasons to employ output based allowance systems is to reduce the negative effects of reduction costs on industrial outputs. They are expressed as percent growth rates for each 5-year period in table III.6

Table III.6. Outputs in physical units

		Average annual Growths				Average annual growth 2000-2020
		2000-2005	2005-2010	2010-2015	2015-2020	
BASE	EPG-Coal	1.05%	3.66%	1.21%	-0.14%	**1.44%**
	EPG-Gas	9.62%	-4.88%	1.72%	3.49%	**2.36%**
	Chemicals	3.00%	2.72%	3.38%	2.76%	**2.96%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	2.16%	1.29%	-0.29%	1.30%	**1.11%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.92%	8.87%	1.62%	0.00%	**6.19%**
	Pulp & Paper	1.25%	1.24%	1.12%	1.15%	**1.19%**
	Oil refining	-1.35%	0.35%	4.31%	0.62%	**0.96%**
Case 4a	EPG-Coal	0.51%	-1.00%	-0.25%	-1.32%	**-0.52%**
	EPG-Gas	10.31%	2.00%	3.06%	3.99%	**4.79%**
	Chemicals	3.00%	-2.24%	0.39%	2.23%	**0.83%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	-2.61%	-3.00%	-3.53%	0.00%	**-2.30%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	15.03%	8.87%	1.62%	0.00%	**6.21%**
	Pulp & Paper	1.25%	-0.87%	-1.23%	1.15%	**0.07%**
	Oil refining	-1.50%	0.06%	4.34%	0.61%	**0.85%**
Case 6	EPG-Coal	1.57%	2.41%	0.35%	-0.16%	**1.04%**
	EPG-Gas	8.45%	-3.25%	5.28%	4.13%	**3.56%**
	Chemicals	3.00%	2.72%	2.23%	2.07%	**2.50%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	2.16%	-0.83%	-1.72%	0.00%	**-0.11%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.99%	8.87%	1.62%	0.00%	**6.20%**
	Pulp & Paper	1.25%	1.24%	-0.99%	1.16%	**0.66%**
	Oil refining	-1.50%	0.10%	4.35%	0.65%	**0.88%**
Case 7	EPG-Coal	1.57%	2.46%	0.29%	-0.16%	**1.04%**
	EPG-Gas	8.54%	-3.40%	5.44%	4.14%	**3.59%**
	Chemicals	3.00%	2.72%	2.23%	2.07%	**2.50%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	2.16%	-0.83%	-1.38%	0.04%	**-0.01%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.99%	8.87%	1.62%	0.00%	**6.20%**
	Pulp & Paper	1.25%	1.24%	-0.99%	1.16%	**0.66%**
	Oil refining	-1.50%	0.10%	4.35%	0.65%	**0.88%**

3.4 Outputs and Emission Intensities

Outputs are an important class of results, since one of the main reasons to employ output based allowance systems is to reduce the negative effects of reduction costs on industrial outputs. They are expressed as percent growth rates for each 5-year period in table III.6

Table III.6. Outputs in physical units

		Average annual Growths				Average annual growth 2000-2020
		2000-2005	2005-2010	2010-2015	2015-2020	
BASE	EPG-Coal	1.05%	3.66%	1.21%	-0.14%	**1.44%**
	EPG-Gas	9.62%	-4.88%	1.72%	3.49%	**2.36%**
	Chemicals	3.00%	2.72%	3.38%	2.76%	**2.96%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	2.16%	1.29%	-0.29%	1.30%	**1.11%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.92%	8.87%	1.62%	0.00%	**6.19%**
	Pulp & Paper	1.25%	1.24%	1.12%	1.15%	**1.19%**
	Oil refining	-1.35%	0.35%	4.31%	0.62%	**0.96%**
Case 4a	EPG-Coal	0.51%	-1.00%	-0.25%	-1.32%	**-0.52%**
	EPG-Gas	10.31%	2.00%	3.06%	3.99%	**4.79%**
	Chemicals	3.00%	-2.24%	0.39%	2.23%	**0.83%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	-2.61%	-3.00%	-3.53%	0.00%	**-2.30%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	15.03%	8.87%	1.62%	0.00%	**6.21%**
	Pulp & Paper	1.25%	-0.87%	-1.23%	1.15%	**0.07%**
	Oil refining	-1.50%	0.06%	4.34%	0.61%	**0.85%**
Case 6	EPG-Coal	1.57%	2.41%	0.35%	-0.16%	**1.04%**
	EPG-Gas	8.45%	-3.25%	5.28%	4.13%	**3.56%**
	Chemicals	3.00%	2.72%	2.23%	2.07%	**2.50%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	2.16%	-0.83%	-1.72%	0.00%	**-0.11%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.99%	8.87%	1.62%	0.00%	**6.20%**
	Pulp & Paper	1.25%	1.24%	-0.99%	1.16%	**0.66%**
	Oil refining	-1.50%	0.10%	4.35%	0.65%	**0.88%**
Case 7	EPG-Coal	1.57%	2.46%	0.29%	-0.16%	**1.04%**
	EPG-Gas	8.54%	-3.40%	5.44%	4.14%	**3.59%**
	Chemicals	3.00%	2.72%	2.23%	2.07%	**2.50%**
	Gas	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Cement	2.16%	-0.83%	-1.38%	0.04%	**-0.01%**
	Oil Conv	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.99%	8.87%	1.62%	0.00%	**6.20%**
	Pulp & Paper	1.25%	1.24%	-0.99%	1.16%	**0.66%**
	Oil refining	-1.50%	0.10%	4.35%	0.65%	**0.88%**

Commentary

- The outputs of Oil sands, Conventional oil, and Gas, are unaffected by GHG emission constraints in all three cases. Oil refining is only slightly affected.
- In Case 4a, the growth rates of some industrial sectors are severely reduced starting in 2010 (e.g. EPG-coal, Chemicals, Cement, Pulp and Paper). The growth rate of EPG-gas is more than doubled.
- Main result: In Cases 6 and 7, the output based allocation scheme partially succeeds in maintaining the growth rates of those industries that are severely affected in Case 4a. Chemicals fully recovers its Base case output, whereas EPG-coal, Cement, and Pulp and Paper partially recover their base case growth rates. The growth rate of EPG-Gas is reduced compared to Case 4a, but still much above that in Base.

Table III.7. Emission intensities

7a. GHG intensities		BASE	Case 4a	Case 6	Case 7
	units	2020	2020	2020	2020
EPG-COAL	kt/PJ	333	243	260	262
EPG-GAS	kt/PJ	97.0	127.1	107.3	87.7
GAS	kt/PJ	3888	3602	2521	2276
CONV OIL	kt/PJ	1.19	1.20	1.20	1.21
OIL REFINING	kt/Mbbl	2668	3403	2636	2587
OIL SANDS	kt/PJ	32	31	32	35
CHEMICALS	kt/Mt	6.4	2.7	3.5	3.5
CEMENT	kt/Mt	6821	3547	5257	5058
PULP & PAPER	kt/Mt	7.67	5.93	5.40	5.23
7b. NOx intensities		**BASE**	**Case 4a**	**Case 6**	**Case 7**
	units	**2020**	**2020**	**2020**	**2020**
EPG-COAL	kt/PJ	0.57	0.37	0.37	0.37
EPG-GAS	kt/PJ	0.060	0.082	0.066	0.054
GAS	kt/PJ	31.35	21.30	14.90	13.45
CONV OIL	kt/PJ	0.006	0.006	0.006	0.006
OIL REFINING	kt/Mbbl	1.95	2.81	2.17	2.13
OIL SANDS	kt/PJ	0.084	0.088	0.091	0.100
CHEMICALS	kt/Mt	0.0089	0.0032	0.0042	0.0042
CEMENT	kt/Mt	16.45	8.67	12.77	12.29
PULP & PAPER	kt/Mt	0.032	0.026	0.023	0.023
7c. SOx intensities		**BASE**	**Case 4a**	**Case 6**	**Case 7**
	units	**2020**	**2020**	**2020**	**2020**
EPG-COAL	kt/PJ	0.81	0.67	0.65	0.65
EPG-GAS	kt/PJ	0.00	0.00	0.00	0.00
GAS	kt/PJ	19.48	5.43	3.32	3.00
CONV OIL	kt/PJ	0.00	0.00	0.00	0.00
OIL REFINING	kt/Mbbl	5.40	5.09	2.85	2.80
OIL SANDS	kt/PJ	0.081	0.085	0.088	0.096
CHEMICALS	kt/Mt	–	--	--	--
CEMENT	kt/Mt	9.74	4.40	6.48	6.24
PULP & PAPER	kt/Mt	0.02	0.01	0.01	0.01

Commentary

We now compare the allocation systems in their ability to induce reductions of their emission intensities.

First, *everything equal otherwise,* both allocation systems are neutral with respect to future emission reductions, since they are both based on past emissions only. However,

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7a. GHG intensities		BASE	Case 4a	Case 6	Case 7
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PULP & PAPER	kt/Mt	7.67	5.93	5.40	5.23
7b. NOx intensities		BASE	Case 4a	Case 6	Case 7
	units	2020	2020	2020	2020
EPG-COAL	kt/PJ	0.57	0.37	0.37	0.37
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Commentary

We now compare the allocation systems in their ability to induce reductions of their emission intensities.

First, *everything equal otherwise,* both allocation systems are neutral with respect to future emission reductions, since they are both based on past emissions only. However, since an output based permit allocation system supports future production, it will reward those sectors that can achieve lower emission intensities at reasonable cost (e.g. via efficiency improvements, or other such means). In contrast, a lump sum permit allocation system is completely disconnected from the future behaviour of sectors.

Therefore, while it is clear that the presence of emission targets always has the effect of lowering emission intensities, it is *not a priori clear* which of the two allowance systems induces the largest reductions of emission intensities.

In the case of Alberta, table III.7 shows that output based allocations (case 7) induces lower emission intensities for four sectors (EPG-gas, Gas, Oil refining, and Pulp and Paper), while lump sum allocation (case 4a) does so for four sectors (EPG-coal, oil sands, chemicals, and cement).

3.5 Impacts on Profits

Table III.8: Profit changes relative to Base, before and after paying for permits

NPV in 2000 (1995 M$)		Case 4a	Case 6	Case 7
EPG coal	Gross profit change	442	-169	-189
	permit cost	-522	404	415
	net profit change	**964**	**-573**	**-605**
EPG gas	Gross profit change	269	-69	-74
	permit cost	140	35	34
	net profit change	**128**	**-104**	**-108**
EPG noncov	Gross profit change	30	-40	-44
	permit cost	0	0	0
	net profit change	**30**	**-40**	**-44**
GAS	Gross profit change	-594	-91	-80
	permit cost	-476	-97	-55
	net profit change	**-118**	**6**	**-25**
CHEMICALS	Gross profit change	461	86	82
	permit cost	-133	61	57
	net profit change	**594**	**25**	**25**
CEMENT	Gross profit change	-2	20	18
	permit cost	-58	9	10
	net profit change	**57**	**11**	**8**
MINING	Gross profit change	23	23	23
	permit cost	3	3	3
	net profit change	**20**	**20**	**20**
P&P	Gross profit change	253	247	250
	permit cost	3	16	16
	net profit change	**251**	**231**	**233**
OTH INDUSTRY	Gross profit change	35	20	19
	permit cost	-38	-46	-46
	net profit change	**73**	**66**	**64**
CONV OIL	Gross profit change	63	108	110
	permit cost	-259	34	26
	net profit change	**322**	**74**	**84**
OIL REFINING	Gross profit change	472	229	221
	permit cost	-71	32	34
	net profit change	**542**	**196**	**187**
OIL SANDS	Gross profit change	-43	62	64
	permit cost	1612	334	302
	net profit change	**-1655**	**-272**	**-238**
Wood, prod	Gross profit change	0	0	0
	permit cost	0	0	0
	net profit change	**-0.1**	**-0.2**	**-0.2**
Total Industry	Gross profit change	1411	427	400
	permit cost	203	787	798
	net profit change	**1208**	**-360**	**-398**

Note: All profits and costs are relative to BASE case

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Total Industry	Gross profit change	1411	427	400
	permit cost	203	787	798
	net profit change	**1208**	**-360**	**-398**

Note: All profits and costs are relative to BASE case

Commentary

- In Case 4a, all profits are larger than in Base, except for Oil Sands
- Results for cases 6 and 7 are fairly close together, signalling that the allocation method for CAC's has a relatively small impact on profits (already noted).
- Main findings:
  a. Output based allocations (cases 6 and 7) reduce overall profit changes, but also reduce the ***variance*** of profit changes. For instance, Oil Sands profits are much better 'protected' than in case 4a, and the rather large profit increases observed in the Chemicals and the conventional oil sectors in Case 4a (which were partly due to large sales of permits) are much reduced in cases 6 and 7.
  b. The case of EPG is different: both sub-sectors now show a loss of profit compared to Base (they are the only subsectors showing a loss in cases 6 and 7). This is the result of lower electricity prices in Cases 6 and 7 versus Case 4a, and a less advantageous allocation method; indeed, neither the coal fired nor the gas fired subsectors are capable of sufficiently reducing their GHG intensities or of increasing their output so as to benefit from the output based allocation scheme. However, the output based allocation schemes do allow the electricity production level to almost go back to that of the base case (table 8), which is a primary objective of such allocation schemes.

- Conclusion: the output based allocation schemes 'smooth out' the profit variations observed in Case 4a. With Cases 6 and 7, the industrial sectors are much closer to the Base case than with a lump sum allocation.

3.6 Electricity Generation

Table III. 9. Electricity generation

Generation TWh/yr		2000	2005	2010	2015	2020
BASE	ELE (BIO)	0.4	0	0	0.9	1.4
	ELE (COAL)	44.1	46.5	55.6	59	58.6
	ELE (GAS)	12.5	19.8	15.4	16.8	19.9
	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.5**	**68.8**	**73.6**	**79.3**	**82.5**
Case 4a	ELE (BIO)	0.4	0	0.1	0.6	1.1
	ELE (COAL)	44.1	45.2	43	42.5	39.7
	ELE (GAS)	12.4	20.3	22.4	26.1	31.7
	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.4**	**68.1**	**68**	**71.7**	**75.1**
Case 6	ELE (BIO)	0.4	0	0.1	0.1	0.1
	ELE (COAL)	44.1	47.7	53.7	54.6	54.2
	ELE (GAS)	12.3	18.4	15.6	20.2	24.7
	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.3**	**68.6**	**71.9**	**77.4**	**81.5**
Case 7	ELE (BIO)	0.4	0	0.1	0.1	0.1
	ELE (COAL)	44.1	47.7	53.8	54.6	54.2
	ELE (GAS)	12.3	18.5	15.5	20.3	24.8
	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.3**	**68.7**	**72**	**77.5**	**81.6**

Commentary

- Total generation drops markedly in Case 4a, but gets back to almost Base case level in cases 6 and 7. This is caused by electricity prices, which increase in Case 4a (due to abatement actions) but not in Cases 6 and 7, thanks to the 'subsidy' provided by the output based allocation scheme. Table III.10 (electricity prices) confirms these assertions
- While gas fired generation was much enhanced in Case 4a, it is much less so in cases 6 and 7, although still larger than in Base case. Nevertheless, new coal based generation is moderately affected in cases 6 and 7 (only 4 TWh lower than in Base).

Table III.10. Electricity prices

cents/kWh	2005	2010	2015	2020
BASE	3.90	3.55	3.66	3.42
Case 4a	3.90	3.91	3.77	3.91
Case 6	3.89	3.46	3.42	3.53
Case 7	3.89	3.44	3.41	3.53
% change wrt base	**2005**	**2010**	**2015**	**2020**
BASE	0%	0%	0%	0%
Case 4a	0%	10%	3%	14%
Case 6	0%	-3%	-7%	3%
Case 7	0%	-3%	-7%	3%

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	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
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	ELE (GAS)	12.4	20.3	22.4	26.1	31.7
	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.4**	**68.1**	**68**	**71.7**	**75.1**
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	ELE (GAS)	12.3	18.4	15.6	20.2	24.7
	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.3**	**68.6**	**71.9**	**77.4**	**81.5**
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	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
	Total	**59.3**	**68.7**	**72**	**77.5**	**81.6**

Commentary

- Total generation drops markedly in Case 4a, but gets back to almost Base case level in cases 6 and 7. This is caused by electricity prices, which increase in Case 4a (due to abatement actions) but not in Cases 6 and 7, thanks to the 'subsidy' provided by the output based allocation scheme. Table III.10 (electricity prices) confirms these assertions
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Case 6	3.89	3.46	3.42	3.53
Case 7	3.89	3.44	3.41	3.53
% change wrt base	**2005**	**2010**	**2015**	**2020**
BASE	0%	0%	0%	0%
Case 4a	0%	10%	3%	14%
Case 6	0%	-3%	-7%	3%
Case 7	0%	-3%	-7%	3%

4. Sensitivity Analysis on Gas price

4.1 Description of Case 8

Case 8 is a variant of case 7. The only difference between the two is that the price of natural gas is assumed to be higher in Case 8. More precisely, the price of gas delivered to Industry is assumed to be equal to $5/GJ (expressed in 2000 C$) throughout the planning horizon 2000 to 2020 (whereas it was close to $4.00/GJ in the original Base case and in Case 7). The price of exported gas follows the same upward shift as the domestic price.

Note that the study of this case requires a re-run of the Base case with the new gas prices. The new base case is denoted as: BASE 8.

We present 10 tables, showing respectively: the loss of total surplus (table IV.1), the shadow prices of the three pollutants (table IV.2), the emissions by (sub)sector (table IV.3), the reductions by (sub)sector (table IV.4), the permit trading and/or banking by (sub)sector (table IV.5), the outputs of each (sub)sector in physical units (table IV.6), the production of oil and oil sands (table IV.7), the profit changes by (sub)sector (table IV.8), the electricity generation mix (table IV.9), and the electricity prices (table IV.10). Each table is followed by a set of brief comments.

In order to facilitate comparisons, we present the results of cases 7 and 8 side by side. In addition, whenever Base case results are needed, they are presented for both the original Base case and the Base case with high gas price. The results of Case 8 should be compared to those of the new base case BASE_8, whereas the results of Case 7 should be compared to those in the original Base case.

4.2 Main Findings

The main finding (and main difference with previous runs) is that the increased price of gas provokes a significant postponement of a portion of oil sands projects. This happens because oil sands production requires significant amounts of natural gas. Therefore, the use of gas in oil sands is in direct competition with additional exports of natural gas. The drop in oil sands production from BASE to BASE_8 is severe in 2010 and 2015, but not in 2020, when oil sands production is the same in both base cases (see table IV.7).

This explains most of the differences between the results of Cases 7 and 8. For instance, the emissions from the Oil Sands sector are naturally low in 2010 and 2015, and thus permit the sale of GHG permits in 2010 and the banking of CAC permits in 2010 and 2020, to be cashed in 2020 (when emissions from oil sands increase again). This in turn allows the price of CAC permits to be even lower than it was in Case 7 (Table IV.2). Another major consequence of the reduced emissions in 2010 and 2015 is that fewer reduction measures are needed in most sectors, and hence their impact on outputs is now reduced to zero (Table IV.1).

Finally, another consequence of the high gas price is that gas fired electricity generation plays an even smaller role in case 8 than it did in case 7.

4.3 Detailed Results

Table IV.1. Loss of total surplus (costs)

	Case 7	Case 8
Permit Cost (GHG)	752	381
Technology Cost	-1360	-481
Demand Loss	978	0
Surplus Loss	370	-100

Note: Case 7 costs are relative to BASE, whereas Case 8 costs are relative to BASE_8

Commentary

- The permit cost in case 8 is much lower than in case 7. As alluded to above, this is due to the much reduced oil sands production, which decreases emissions of GHG's. See table 7 for details on oil sands production.
- Case 8 also shows higher technological cost. This is due to higher production levels in all sectors except Oil Sands (see table 6).
- In case 8, demand loss is zero, signalling that the output based allocation fully succeeds in maintaining production at the base case levels in the three end-use sectors (Chemicals, Cement, P&P, see table 6)
- Total surplus of case 8 experiences *a net gain* of $M 100. This apparent paradox is explained by the fact that there are enough no-regret actions to decrease costs more than they increase due to abatement measures.
- Important remark: A full comparison of the low versus the high gas price cases is required to evaluate the relative costs of BASE and BASE_8. A separate calculation shows that BASE_8 has a total cost 7.7 B$ less than BASE. This is due to higher revenues from gas exports, which more than compensate for lost oil sands production and exports.

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- Important remark: A full comparison of the low versus the high gas price cases is required to evaluate the relative costs of BASE and BASE_8. A separate calculation shows that BASE_8 has a total cost 7.7 B$ less than BASE. This is due to higher revenues from gas exports, which more than compensate for lost oil sands production and exports.

Table IV.2. Emission Prices (marginal reduction costs)

$/tonne		2010	2015	2020
GHG covered	Case 7	9.2	12.0	14.7
	Case 8	9.2	12.0	14.7
GHG uncovered	Case 7	0.0	38.0	33.5
	Case 8	0.0	35.3	35.7
NOx	Case 7	61	98	158
	Case 8	61	61	98
SOx	Case 7	136	218	352
	Case 8	85	137	221

Commentary

- The main observation is that SOx and NOx prices in case 8 are even lower than those in Case 7. This is due to the fact that oil sands emit less in Case 8 (since its output is lower)

Table IV.3. Emissions for Base Case, Case 7 Base 8 and Case 8

emissions of GHG		BASE					Case 7					BASE_8					Case 8				
Mt/yr		2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	**GHG**	42.0	44.1	52.6	56.1	55.7	42.0	45.3	50.8	51.6	51.2	42.0	45.3	56.5	56.1	55.7	42.0	45.3	52.0	56.1	55.7
EPG gas	**GHG**	4.3	7.7	5.8	5.9	6.9	4.2	6.4	5.1	6.5	7.8	4.1	6.1	4.4	4.7	6.9	4.1	5.9	4.8	4.1	6.3
GAS	**GHG**	36.5	43.8	41.0	41.9	41.7	36.5	43.9	36.3	35.1	34.5	36.5	44.4	41.6	42.9	41.8	36.5	44.4	36.9	36.3	35.0
CHEMICALS	**GHG**	11.6	12.1	13.8	16.2	18.4	11.6	12.1	13.8	15.3	16.8	11.6	12.1	13.8	16.2	18.4	11.6	12.1	13.8	16.2	18.4
CEMENT	**GHG**	2.1	2.0	2.3	2.3	2.5	2.1	2.0	2.0	2.0	2.0	2.1	2.0	2.3	2.3	2.5	2.1	2.0	2.3	2.3	2.5
MINING	**GHG**	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.4	0.5	0.6	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.5	0.6	0.6
P&P	**GHG**	0.6	0.7	0.9	1.0	1.2	0.6	0.7	0.8	0.9	1.0	0.6	0.8	1.0	1.3	1.4	0.6	0.8	1.0	1.2	1.3
OTH INDUSTRY	**GHG**	4.7	5.0	5.3	5.6	5.6	4.6	4.8	4.8	4.8	4.6	4.8	5.5	5.8	6.3	6.1	4.7	4.9	5.1	5.2	5.1
CONV OIL	**GHG**	12.0	10.6	9.9	9.3	8.3	12.0	10.6	9.7	9.2	8.1	12.0	10.6	9.9	9.3	8.3	12.0	10.6	9.7	9.2	8.1
OIL REFINING	**GHG**	6.5	6.0	6.1	7.6	7.8	6.4	5.6	5.6	7.0	6.8	6.6	6.2	6.4	8.0	8.2	6.6	5.7	5.8	7.0	7.0
OIL SANDS	**GHG**	20.3	38.0	57.2	64.1	64.2	20.2	38.0	57.2	64.1	59.2	20.5	27.5	48.7	35.7	64.2	20.5	27.5	48.7	35.7	59.2
Total covered	**GHG**	**140.9**	**170.6**	**195.3**	**210.6**	**213.0**	**140.5**	**169.9**	**186.6**	**196.9**	**192.8**	**141.2**	**160.9**	**190.7**	**183.3**	**214.2**	**141.1**	**159.7**	**180.6**	**173.8**	**199.2**
CHEMICALS	**NOx**	14.4	16.7	19.1	22.6	25.9	14.4	16.7	16.6	18.1	20.0	14.4	16.7	19.1	22.6	25.9	14.4	16.7	16.6	19.6	21.9
CEMENT	**NOx**	4.8	5.4	5.7	5.6	6.0	4.8	5.4	5.2	4.8	4.8	4.8	5.4	5.7	5.6	6.0	4.8	5.4	5.7	5.6	6.0
P&P	**NOx**	3.8	4.0	4.3	4.5	4.8	3.8	4.0	4.3	4.1	4.3	3.8	4.0	4.3	4.5	4.8	3.8	4.0	4.3	4.5	4.8
EPG coal	**NOx**	81.6	82.7	92.2	96.1	96.1	81.6	84.2	77.1	76.5	71.9	81.6	84.2	97.0	96.1	96.1	81.6	84.2	79.8	84.4	82.0
EPG gas	**NOx**	6.8	11.5	5.3	3.7	4.3	6.7	8.2	2.9	3.9	4.8	6.6	8.1	2.5	2.7	4.3	6.6	7.4	2.7	2.1	3.7
GAS_ALL	**NOx**	249.7	315.6	317.7	327.6	336.2	249.7	315.7	246.1	195.4	204.0	249.7	316.4	318.5	329.7	336.4	249.7	316.4	284.5	216.5	204.0
CONV OIL	**NOx**	66.3	59.8	54.2	49.6	42.4	66.3	59.8	53.8	49.2	42.0	66.3	59.8	54.2	49.6	42.4	66.3	59.8	55.9	51.3	44.5
OIL REFINING	**NOx**	4.7	4.4	4.5	5.5	5.7	4.7	4.4	4.4	5.4	5.6	4.8	4.5	4.7	5.9	6.0	4.8	4.4	4.5	5.6	5.7
OIL SANDS	**NOx**	54.0	105.3	156.7	170.3	170.3	53.8	105.3	156.7	170.3	170.3	54.6	78.6	136.8	99.4	170.3	54.7	78.6	136.8	99.4	170.3
WOOD PROD	**NOx**	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7
Total covered	**NOx**	**491.2**	**611.0**	**665.7**	**691.9**	**698.3**	**491.0**	**609.2**	**573.0**	**534.1**	**534.6**	**491.8**	**583.3**	**648.7**	**622.4**	**698.9**	**491.9**	**582.5**	**596.7**	**495.4**	**549.7**
CEMENT	**SOx**	2.9	3.2	3.4	3.3	3.6	2.9	3.2	3.1	2.4	2.4	2.9	3.2	3.4	3.3	3.6	2.9	3.2	3.4	3.0	3.1
P&P	**SOx**	2.0	2.2	2.3	2.4	2.6	2.0	2.2	2.3	2.2	2.3	2.0	2.2	2.3	2.4	2.6	2.0	2.2	2.3	2.4	2.6
EPG coal	**SOx**	128.1	126.0	129.3	135.0	135.0	128.1	128.2	126.0	127.0	127.0	128.1	128.2	136.2	135.0	135.0	128.1	128.2	128.2	135.0	135.0
EPG gas	**SOx**	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.00	0.01
GAS_ALL	**SOx**	227.5	216.4	210.9	210.4	208.9	227.5	216.4	143.0	86.0	45.4	227.5	216.4	210.9	210.4	208.9	227.5	216.4	154.0	142.5	45.4
CONV OIL	**SOx**	32.4	19.4	18.5	18.0	16.3	32.4	19.4	18.5	17.9	16.3	32.4	19.4	18.5	18.0	16.3	32.4	19.4	18.5	17.9	16.3
OIL REFINING	**SOx**	13.1	12.2	12.4	15.4	15.8	13.0	12.1	12.2	9.8	7.4	13.3	12.6	12.9	16.2	16.7	13.3	12.3	12.5	12.5	10.4
OIL SANDS	**SOx**	94.0	116.9	168.7	173.7	164.0	93.7	116.9	168.7	173.7	164.0	95.2	87.3	147.3	101.3	164.0	95.2	87.3	147.3	101.3	164.0
Total covered	**SOx**	**500.0**	**496.4**	**545.6**	**558.2**	**546.2**	**499.7**	**498.4**	**473.8**	**419.0**	**364.8**	**501.4**	**469.2**	**531.6**	**486.7**	**547.0**	**501.4**	**468.9**	**466.2**	**414.7**	**376.7**

Table IV.2. Emission Prices (marginal reduction costs)

$/tonne		2010	2015	2020
GHG covered	Case 7	9.2	12.0	14.7
	Case 8	9.2	12.0	14.7
GHG uncovered	Case 7	0.0	38.0	33.5
	Case 8	0.0	35.3	35.7
NOx	Case 7	61	98	158
	Case 8	61	61	98
SOx	Case 7	136	218	352
	Case 8	85	137	221

Commentary

- The main observation is that SOx and NOx prices in case 8 are even lower than those in Case 7. This is due to the fact that oil sands emit less in Case 8 (since its output is lower)

Table IV.3. Emissions for Base Case, Case 7 Base 8 and Case 8

emissions of GHG		BASE					Case 7					BASE_8					Case 8				
Mt/year		2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	GHG	42.0	44.1	52.6	56.1	55.7	42.0	45.3	50.8	51.6	51.2	42.0	45.3	56.5	56.1	55.7	42.0	45.3	52.0	56.1	55.7
EPG gas	GHG	4.3	7.7	5.8	5.9	6.9	4.2	6.4	5.1	6.5	7.8	4.1	6.1	4.4	4.7	6.9	4.1	5.9	4.8	4.1	6.3
GAS	GHG	36.5	43.8	41.0	41.9	41.7	36.5	43.9	36.3	35.1	34.5	36.5	44.4	41.6	42.9	41.8	36.5	44.4	36.9	36.3	35.0
CHEMICALS	GHG	11.6	12.1	13.8	16.2	18.4	11.6	12.1	13.8	15.3	16.8	11.6	12.1	13.8	16.2	18.4	11.6	12.1	13.8	16.2	18.4
CEMENT	GHG	2.1	2.0	2.3	2.3	2.5	2.1	2.0	2.0	2.0	2.0	2.1	2.0	2.3	2.3	2.5	2.1	2.0	2.3	2.3	2.5
MINING	GHG	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.4	0.5	0.6	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.5	0.6	0.6
P&P	GHG	0.6	0.7	0.9	1.0	1.2	0.6	0.7	0.8	0.9	1.0	0.6	0.8	1.0	1.3	1.4	0.6	0.8	1.0	1.2	1.3
OTH INDUSTRY	GHG	4.7	5.0	5.3	5.6	5.6	4.6	4.8	4.8	4.8	4.6	4.8	5.5	5.8	6.3	6.1	4.7	4.9	5.1	5.2	5.1
CONV OIL	GHG	12.0	10.6	9.9	9.3	8.3	12.0	10.6	9.7	9.2	8.1	12.0	10.6	9.9	9.3	8.3	12.0	10.6	9.7	9.2	8.1
OIL REFINING	GHG	6.5	6.0	6.1	7.6	7.8	6.4	5.6	5.6	7.0	6.8	6.6	6.2	6.4	8.0	8.2	6.6	5.7	5.8	7.0	7.0
OIL SANDS	GHG	20.3	38.0	57.2	64.1	64.2	20.2	38.0	57.2	64.1	59.2	20.5	27.5	48.7	35.7	64.2	20.5	27.5	48.7	35.7	59.2
Total covered	**GHG**	**140.9**	**170.6**	**195.3**	**210.6**	**213.0**	**140.5**	**169.9**	**186.6**	**196.9**	**192.8**	**141.2**	**160.9**	**190.7**	**183.3**	**214.2**	**141.1**	**159.7**	**180.6**	**173.8**	**199.2**
CHEMICALS	NOx	14.4	16.7	19.1	22.6	25.9	14.4	16.7	16.6	18.1	20.0	14.4	16.7	19.1	22.6	25.9	14.4	16.7	16.6	19.6	21.9
CEMENT	NOx	4.8	5.4	5.7	5.6	6.0	4.8	5.4	5.2	4.8	4.8	4.8	5.4	5.7	5.6	6.0	4.8	5.4	5.7	5.6	6.0
P&P	NOx	3.8	4.0	4.3	4.5	4.8	3.8	4.0	4.3	4.1	4.3	3.8	4.0	4.3	4.5	4.8	3.8	4.0	4.3	4.5	4.8
EPG coal	NOx	81.6	82.7	92.2	96.1	96.1	81.6	84.2	77.1	76.5	71.9	81.6	84.2	97.0	96.1	96.1	81.6	84.2	79.8	84.4	82.0
EPG gas	NOx	6.8	11.5	5.3	3.7	4.3	6.7	8.2	2.9	3.9	4.8	6.6	8.1	2.5	2.7	4.3	6.6	7.4	2.7	2.1	3.7
GAS_ALL	NOx	249.7	315.6	317.7	327.6	336.2	249.7	315.7	246.1	195.4	204.0	249.7	316.4	318.5	329.7	336.4	249.7	316.4	284.5	216.5	204.0
CONV OIL	NOx	66.3	59.8	54.2	49.6	42.4	66.3	59.8	53.8	49.2	42.0	66.3	59.8	54.2	49.6	42.4	66.3	59.8	55.9	51.3	44.5
OIL REFINING	NOx	4.7	4.4	4.5	5.5	5.7	4.7	4.4	4.4	5.4	5.6	4.8	4.5	4.7	5.9	6.0	4.8	4.4	4.5	5.6	5.7
OIL SANDS	NOx	54.0	105.3	156.7	170.3	170.3	53.8	105.3	156.7	170.3	170.3	54.6	78.6	136.8	99.4	170.3	54.7	78.6	136.8	99.4	170.3
WOOD PROD	NOx	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7	5.2	5.5	5.9	6.3	6.7
Total covered	**NOx**	**491.2**	**611.0**	**665.7**	**691.9**	**698.3**	**491.0**	**609.2**	**573.0**	**534.1**	**534.6**	**491.8**	**583.3**	**648.7**	**622.4**	**698.9**	**491.9**	**582.5**	**596.7**	**495.4**	**549.7**
CEMENT	SOx	2.9	3.2	3.4	3.3	3.6	2.9	3.2	3.1	2.4	2.4	2.9	3.2	3.4	3.3	3.6	2.9	3.2	3.4	3.0	3.1
P&P	SOx	2.0	2.2	2.3	2.4	2.6	2.0	2.2	2.3	2.2	2.3	2.0	2.2	2.3	2.4	2.6	2.0	2.2	2.3	2.4	2.6
EPG coal	SOx	128.1	126.0	129.3	135.0	135.0	128.1	128.2	126.0	127.0	127.0	128.1	128.2	136.2	135.0	135.0	128.1	128.2	128.2	135.0	135.0
EPG gas	SOx	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01	0.00	0.01
GAS_ALL	SOx	227.5	216.4	210.9	210.4	208.9	227.5	216.4	143.0	86.0	45.4	227.5	216.4	210.9	210.4	208.9	227.5	216.4	154.0	142.5	45.4
CONV OIL	SOx	32.4	19.4	18.5	18.0	16.3	32.4	19.4	18.5	17.9	16.3	32.4	19.4	18.5	18.0	16.3	32.4	19.4	18.5	17.9	16.3
OIL REFINING	SOx	13.1	12.2	12.4	15.4	15.8	13.0	12.1	12.2	9.8	7.4	13.3	12.6	12.9	16.2	16.7	13.3	12.3	12.5	12.5	10.4
OIL SANDS	SOx	94.0	116.9	168.7	173.7	164.0	93.7	116.9	168.7	173.7	164.0	95.2	87.3	147.3	101.3	164.0	95.2	87.3	147.3	101.3	164.0
Total covered	**SOx**	**500.0**	**496.4**	**545.6**	**558.2**	**546.2**	**499.7**	**498.4**	**473.8**	**419.0**	**364.8**	**501.4**	**469.2**	**531.6**	**486.7**	**547.0**	**501.4**	**468.9**	**466.2**	**414.7**	**376.7**

Table IV.4. Reductions relative to Base

GHG [illegible] relative				[illegible]					Case 8		
to BASE		2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	**GHG**	0%	3%	-3%	-8%	-8%	0%	0%	-8%	0%	0%
EPG gas		-3%	-16%	-11%	9%	13%	1%	-2%	11%	-14%	-9%
GAS		0%	0%	-12%	-16%	-17%	0%	0%	-11%	-15%	-16%
CHEMICALS		0%	0%	0%	-5%	-9%	0%	0%	0%	0%	0%
CEMENT		0%	0%	-11%	-15%	-21%	0%	0%	0%	0%	-1%
MINING		0%	0%	-7%	-6%	-4%	0%	0%	0%	0%	0%
P&P		0%	-6%	-5%	-14%	-13%	0%	0%	0%	-7%	-6%
OTH INDUSTRY		-2%	-3%	-9%	-14%	-18%	-3%	-11%	-12%	-17%	-16%
CONV OIL		0%	0%	-2%	-2%	-2%	0%	0%	-2%	-2%	-2%
OIL REFINING		0%	-8%	-9%	-8%	-13%	0%	-8%	-9%	-13%	-15%
OIL SANDS		0%	0%	0%	0%	-8%	0%	0%	0%	0%	-8%
Total covered		**0%**	**0%**	**-4%**	**-7%**	**-9%**	0%	-1%	-5%	-5%	-7%
CHEMICALS	**NOx**	0%	0%	-13%	-20%	-22%	0%	0%	-13%	-13%	-15%
CEMENT		0%	0%	-10%	-15%	-20%	0%	0%	0%	0%	0%
P&P		0%	0%	0%	-10%	-10%	0%	0%	0%	0%	0%
EPG coal		0%	2%	-16%	-20%	-25%	0%	0%	-18%	-12%	-15%
EPG gas		-1%	-29%	-46%	6%	14%	0%	-9%	5%	-23%	-15%
GAS_ALL		0%	0%	-23%	-40%	-39%	0%	0%	-11%	-34%	-39%
CONV OIL		0%	0%	-1%	-1%	-1%	0%	0%	3%	3%	5%
OIL REFINING		0%	-1%	-2%	-2%	-2%	0%	-2%	-3%	-4%	-5%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WOOD PROD		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		**0%**	**0%**	**-14%**	**-23%**	**-23%**	0%	0%	-8%	-20%	-21%
CEMENT	**SOx**	0%	0%	-10%	-27%	-31%	0%	0%	0%	-11%	-14%
P&P		0%	0%	0%	-10%	-10%	0%	0%	0%	0%	0%
EPG coal		0%	2%	-3%	-6%	-6%	0%	0%	-6%	0%	0%
EPG gas		-2%	-3%	-38%	9%	14%	0%	2%	-6%	-42%	-24%
GAS_ALL		0%	0%	-32%	-59%	-78%	0%	0%	-27%	-32%	-78%
CONV OIL		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OIL REFINING		0%	-1%	-2%	-36%	-54%	0%	-2%	-3%	-23%	-38%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		**0%**	**0%**	**-13%**	**-25%**	**-33%**	0%	0%	-12%	-15%	-31%

Commentary

- Generally, reductions are less marked in Case 8 than in case 7, again because much of the reduction occurs even in the new base case, thanks to the decrease in output of the oil sands sector in 2010 and 2015.
- In addition, the reductions in EPG-gas are now much larger in Case 8, but this is due to the much smaller gas fired electricity generation, as we shall see in table 9. Simultaneously, the EPG-Coal subsector emits more because it produces more than in Case 7.

Table IV.5. Permit trading and banking

[illegible]		Case [illegible]				Case [illegible]			
permit purchases		2010	2015	2020	comments	2010	2015	2020	comments
EPG coal	**GHG**	6.3	8.3	13.7	Buy	4.6	2.8	16.1	Buy
EPG gas	**Mt/yr**	0.5	0.6	1.6	Buy	0.4	-0.2	1.3	Sell, buy
GAS		-1.4	-1.0	3.2	Sell, buy	-2.4	-4.7	4.4	Sell, buy
CHEMICALS		0.5	1.0	3.1	Buy	-0.1	-1.0	3.7	Sell, buy
CEMENT		0.1	0.2	0.4	Buy	0.0	0.0	0.6	Buy
MINING		0.0	0.1	0.2	Buy	0.0	0.1	0.2	Buy
P&P		0.3	0.3	0.5	Buy	0.4	0.5	0.8	Buy
OTH INDUSTRY		-1.2	-1.2	-0.6	sell	-0.9	-0.8	-0.2	Sell
CONV OIL		0.3	0.4	1.2	Buy	-0.1	-0.8	1.4	Sell, buy
OIL REFINING		0.4	0.8	1.2	Buy	0.2	-0.3	1.4	Sell, buy
OIL SANDS		3.3	8.0	10.4	Buy	0.6	-1.2	11.5	Sell, buy
Total covered		**8.8**	**17.5**	**34.9**	**Buy**	**2.9**	**-5.6**	**41.4**	**Sell, buy**
CHEMICALS	**NOx**	-0.4	0.9	3.1	Bank,buy	-1.0	-0.5	3.6	bank, buy
CEMENT	**kt/yr**	0.6	0.9	1.4	Buy	0.5	0.6	1.8	buy
P&P		0.5	0.8	1.2	Buy	0.3	0.5	1.4	buy
EPG coal		-11.5	-4.8	0.2	Bank, sell	-13.8	-13.1	5.2	sell, bank
EPG gas		-4.6	-4.9	-4.8	Sell	-4.4	-4.2	-4.0	sell
GAS_ALL		-18.6	-43.1	-6.9	Sell	11.2	-48.3	-4.5	buy, sell
CONV OIL		0.4	2.5	4.3	Sell	0.7	-0.6	7.1	bank, buy
OIL REFINING		0.5	1.1	1.6	Buy	0.4	0.6	1.7	buy
OIL SANDS		9.5	26.3	42.2	Buy	6.7	6.8	43.5	buy
WOOD PROD		-0.3	0.5	1.6	Bank, buy	-0.3	0.5	1.6	bank, buy
Total covered		**-24**	**-20**	**44**	**Bank**	**0**	**-57.6**	**57.4**	**bank**
CEMENT	**SOx**	1.1	0.9	1.2	Buy	1.1	0.9	1.5	buy
P&P	**kt/yr**	0.9	1.0	1.3	Buy	0.8	0.9	1.5	buy
EPG coal		27.5	41.1	56.8	Buy	22.2	26.0	60.4	buy
EPG gas									
GAS_ALL		-27.7	-60.4	-74.4	Sell	-25.7	-29.4	-72.2	sell
CONV OIL		0.0	2.5	4.7	Buy	-1.0	-0.2	4.9	buy
OIL REFINING		4.5	1.7	0.4	Buy	4.2	2.7	3.4	buy
OIL SANDS		-12.7	4.7	24.7	Bank, buy	-16.2	-13.5	27.3	bank, buy
Total covered		**-6**	**-9**	**15**	**bank**	**-14**	**-13**	**27**	**bank**

Commentary

- The results confirm the comments made earlier to the effect that industries generally have less efforts to do, and buy fewer GHG permits (they even sell permits to the external market in 2015). Banking is more active, because industries take advantage of the low emissions in 2010 and 2015 to bank permits for use in 2020. The net result is that both GHG and CAC emissions in 2020 are significantly higher in case 8 than in case 7.

Table IV.4. Reductions relative to Base

GHG reductions relative				Case 7					Case 8		
to BASE		2000	2005	2010	2015	2020	2000	2005	2010	2015	2020
EPG coal	GHG	0%	3%	-3%	-8%	-8%	0%	0%	-8%	0%	0%
EPG gas		-3%	-16%	-11%	9%	13%	1%	-2%	11%	-14%	-9%
GAS		0%	0%	-12%	-16%	-17%	0%	0%	-11%	-15%	-16%
CHEMICALS		0%	0%	0%	-5%	-9%	0%	0%	0%	0%	0%
CEMENT		0%	0%	-11%	-15%	-21%	0%	0%	0%	0%	-1%
MINING		0%	0%	-7%	-6%	-4%	0%	0%	0%	0%	0%
P&P		0%	-6%	-5%	-14%	-13%	0%	0%	0%	-7%	-6%
OTH INDUSTRY		-2%	-3%	-9%	-14%	-18%	-3%	-11%	-12%	-17%	-16%
CONV OIL		0%	0%	-2%	-2%	-2%	0%	0%	-2%	-2%	-2%
OIL REFINING		0%	-8%	-9%	-8%	-13%	0%	-8%	-9%	-13%	-15%
OIL SANDS		0%	0%	0%	0%	-8%	0%	0%	0%	0%	-8%
Total covered		0%	0%	-4%	-7%	-9%	0%	-1%	-5%	-5%	-7%
CHEMICALS	NOx	0%	0%	-13%	-20%	-22%	0%	0%	-13%	-13%	-15%
CEMENT		0%	0%	-10%	-15%	-20%	0%	0%	0%	0%	0%
P&P		0%	0%	0%	-10%	-10%	0%	0%	0%	0%	0%
EPG coal		0%	2%	-16%	-20%	-25%	0%	0%	-18%	-12%	-15%
EPG gas		-1%	-29%	-46%	6%	14%	0%	-9%	5%	-23%	-15%
GAS_ALL		0%	0%	-23%	-40%	-39%	0%	0%	-11%	-34%	-39%
CONV OIL		0%	0%	-1%	-1%	-1%	0%	0%	3%	3%	5%
OIL REFINING		0%	-1%	-2%	-2%	-2%	0%	-2%	-3%	-4%	-5%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
WOOD PROD		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		0%	0%	-14%	-23%	-23%	0%	0%	-8%	-20%	-21%
CEMENT	SOx	0%	0%	-10%	-27%	-31%	0%	0%	0%	-11%	-14%
P&P		0%	0%	0%	-10%	-10%	0%	0%	0%	0%	0%
EPG coal		0%	2%	-3%	-6%	-6%	0%	0%	-6%	0%	0%
EPG gas		-2%	-3%	-38%	9%	14%	0%	2%	-6%	-42%	-24%
GAS_ALL		0%	0%	-32%	-59%	-78%	0%	0%	-27%	-32%	-78%
CONV OIL		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OIL REFINING		0%	-1%	-2%	-36%	-54%	0%	-2%	-3%	-23%	-38%
OIL SANDS		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total covered		0%	0%	-13%	-25%	-33%	0%	0%	-12%	-15%	-31%

Commentary

- Generally, reductions are less marked in Case 8 than in case 7, again because much of the reduction occurs even in the new base case, thanks to the decrease in output of the oil sands sector in 2010 and 2015.
- In addition, the reductions in EPG-gas are now much larger in Case 8, but this is due to the much smaller gas fired electricity generation, as we shall see in table 9. Simultaneously, the EPG-Coal subsector emits more because it produces more than in Case 7.

Table IV.5. Permit trading and banking

		Case 7				Case 8			
permit purchases		**2010**	**2015**	**2020**	**comments**	**2010**	**2015**	**2020**	**comments**
EPG coal	GHG	6.3	8.3	13.7	Buy	4.6	2.8	16.1	Buy
EPG gas	Mt/yr	0.5	0.6	1.6	Buy	0.4	-0.2	1.3	Sell, buy
GAS		-1.4	-1.0	3.2	Sell, buy	-2.4	-4.7	4.4	Sell, buy
CHEMICALS		0.5	1.0	3.1	Buy	-0.1	-1.0	3.7	Sell, buy
CEMENT		0.1	0.2	0.4	Buy	0.0	0.0	0.6	Buy
MINING		0.0	0.1	0.2	Buy	0.0	0.1	0.2	Buy
P&P		0.3	0.3	0.5	Buy	0.4	0.5	0.8	Buy
OTH INDUSTRY		-1.2	-1.2	-0.6	sell	-0.9	-0.8	-2	Sell
CONV OIL		0.3	0.4	1.2	Buy	-0.1	-0.8	1.4	Sell, buy
OIL REFINING		0.4	0.8	1.2	Buy	0.2	-0.3	1.4	Sell, buy
OIL SANDS		3.3	8.0	10.4	Buy	0.6	-1.2	11.5	Sell, buy
Total covered		8.8	17.5	34.9	**Buy**	2.9	-5.6	41.4	**Sell, buy**
CHEMICALS	NOx	-0.4	0.9	3.1	Bank,buy	-1.0	-0.5	3.6	bank, buy
CEMENT	kt/yr	0.6	0.9	1.4	Buy	0.5	0.6	1.8	buy
P&P		0.5	0.8	1.2	Buy	0.3	0.5	1.4	buy
EPG coal		-11.5	-4.8	0.2	Bank, sell	-13.8	-13.1	5.2	sell, bank
EPG gas		-4.6	-4.9	-4.8	Sell	-4.4	-4.2	-4.0	sell
GAS_ALL		-18.6	-45.1	-6.9	Sell	11.2	-48.3	-4.5	buy, sell
CONV OIL		0.4	2.5	4.3	Sell	0.7	-0.6	7.1	bank, buy
OIL REFINING		0.5	1.1	1.6	Buy	0.4	0.6	1.7	buy
OIL SANDS		9.5	26.3	42.2	Buy	6.7	6.8	43.5	buy
WOOD PROD		-0.3	0.5	1.6	Bank, buy	-0.3	0.5	1.6	bank, buy
Total covered		-24	-20	44	**Bank**	0	-57.6	57.4	**bank**
CEMENT	SOx	1.1	0.9	1.2	Buy	1.1	0.9	1.5	buy
P&P	kt/yr	0.9	1.0	1.3	Buy	0.8	0.9	1.5	buy
EPG coal		27.5	41.1	56.8	Buy	22.2	26.0	60.4	buy
EPG gas									
GAS_ALL		-27.7	-60.4	-74.4	Sell	-25.7	-29.4	-72.2	sell
CONV OIL		0.0	2.5	4.7	Buy	-1.0	-0.2	4.9	buy
OIL REFINING		4.5	1.7	0.4	Buy	4.2	2.7	3.4	buy
OIL SANDS		-12.7	4.7	24.7	Bank, buy	-16.2	-13.5	27.3	bank, buy
Total covered		-6	-9	15	bank	-14	-13	27	bank

Commentary

- The results confirm the comments made earlier to the effect that industries generally have less efforts to do, and buy fewer GHG permits (they even sell permits to the external market in 2015). Banking is more active, because industries take advantage of the low emissions in 2010 and 2015 to bank permits for use in 2020. The net result is that both GHG and CAC emissions in 2020 are significantly higher in case 8 than in case 7.

Table IV.6. Outputs in physical units

[illegible]	[illegible]	Average Growths				Avg growth
		2000-2005	2005-2010	2010-2015	2015-2020	2000-2020
BASE	EPG-COAL	1.05%	3.66%	1.21%	-0.14%	**1.44%**
	EPG-GAS	9.62%	-4.88%	1.72%	3.49%	**2.36%**
	Chemicals	3.00%	2.72%	3.38%	2.76%	**2.96%**
	GAS	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Mining	2.78%	1.98%	2.48%	2.54%	**2.44%**
	Cement	2.16%	1.29%	-0.29%	1.30%	**1.11%**
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.92%	8.87%	1.62%	0.00%	**6.19%**
	Other Manuf	0.70%	0.57%	0.53%	0.52%	**0.58%**
	Pulp and Paper	1.25%	1.24%	1.12%	1.15%	**1.19%**
	Oil refining	-1.35%	0.35%	4.31%	0.62%	**0.96%**
Case 7	EPG-COAL	1.57%	2.46%	0.29%	-0.16%	**1.04%**
	EPG-GAS	8.54%	-3.40%	5.44%	4.14%	**3.59%**
	Chemicals	3.00%	2.72%	2.23%	2.07%	**2.50%**
	GAS	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Mining	2.78%	0.61%	2.73%	2.78%	**2.22%**
	Cement	2.16%	-0.83%	-1.38%	0.04%	**-0.01%**
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	14.99%	8.87%	1.62%	0.00%	**6.20%**
	Other Manuf	0.51%	0.00%	0.00%	0.02%	**0.13%**
	Pulp and Paper	1.25%	1.24%	-0.99%	1.15%	**0.66%**
	Oil refining	-1.50%	0.10%	4.35%	0.65%	**0.88%**
BASE_8	EPG-COAL	1.57%	4.53%	-0.14%	-0.14%	**1.44%**
	EPG-GAS	6.52%	-5.24%	1.53%	8.35%	**2.65%**
	Chemicals	3.00%	2.72%	3.38%	2.76%	**2.96%**
	GAS	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Mining	2.78%	1.98%	2.48%	2.54%	**2.44%**
	Cement	2.16%	1.29%	-0.29%	1.30%	**1.11%**
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	7.85%	12.13%	-6.02%	11.56%	**6.11%**
	Other Manuf	0.70%	0.57%	0.53%	0.52%	**0.58%**
	Pulp and Paper	1.25%	1.24%	1.12%	1.15%	**1.19%**
	Oil refining	-1.13%	0.60%	4.62%	0.54%	**1.14%**
Case 8	EPG-COAL	1.57%	2.92%	1.42%	-0.14%	**1.44%**
	EPG-GAS	7.45%	-3.99%	-1.68%	9.07%	**2.56%**
	Chemicals	3.00%	2.72%	3.38%	2.76%	**2.96%**
	GAS	4.09%	-0.51%	-0.03%	-0.13%	**0.84%**
	Mining	2.78%	1.98%	2.48%	2.54%	**2.44%**
	Cement	2.16%	1.29%	-0.29%	1.30%	**1.11%**
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	**-1.13%**
	Oilsands	7.84%	12.14%	-6.02%	11.56%	**6.11%**
	Other Manuf	0.70%	0.57%	0.53%	0.52%	**0.58%**
	Pulp and Paper	1.25%	1.24%	1.12%	1.15%	**1.19%**
	Oil refining	-1.53%	0.37%	4.35%	0.45%	**0.89%**

Commentary

- The output of Oil sands in BASE_8 and in CASE 8 is severely lower than that in the BASE case or in Case 7 in 2010 and 2015, but gets back to the same level in 2020. All other sectoral outputs are unaffected both in Base 8 and in Case 8. Table 7 shows the amounts of bitumen and synthetic oil in all cases.
- Main result: In Case 8, the lighter burden put on most sectors, together with the output based allocation scheme, allows them to maintain their outputs at the BASE levels. The exception is oil sands, but its output loss in 2010 and 2015 is due to the high price of gas and not to the abatement measures.
- EPG-Gas experiences much less growth in Case 8 than in case 7, obviously a result of the high gas price. EPG-coal benefits from that.

Table IV.7. Oil production

PJ/yr		2000	2005	2010	2015	2020
BASE and Case 7	**Bitumen**	1446	2898	4433	4805	4805
	Conv oil	2132	2023	1934	1873	1700
BASE 8 and Case 8	**Bitumen**	1467	2139	3794	2781	4805
	Conv oil	2132	2023	1934	1873	1700

Table IV.6. Outputs in physical units

		Average Growths				Avg. growth
		2000-2005	2005-2010	2010-2015	2015-2020	2000-2020
BASE	EPG-COAL	1.05%	3.66%	1.21%	-0.14%	1.44%
	EPG-GAS	9.62%	-4.88%	1.72%	3.49%	2.36%
	Chemicals	3.00%	2.72%	3.38%	2.76%	2.96%
	GAS	4.09%	-0.51%	-0.03%	-0.13%	0.84%
	Mining	2.78%	1.98%	2.48%	2.54%	2.44%
	Cement	2.16%	1.29%	-0.29%	1.30%	1.11%
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	-1.13%
	Oilsands	14.92%	8.87%	1.62%	0.00%	6.19%
	Other Manuf	0.70%	0.57%	0.53%	0.52%	0.58%
	Pulp and Paper	1.25%	1.24%	1.12%	1.15%	1.19%
	Oil refining	-1.35%	0.35%	4.31%	0.62%	0.96%
Case 7	EPG-COAL	1.57%	2.46%	0.29%	-0.16%	1.04%
	EPG-GAS	8.54%	-3.40%	5.44%	4.14%	3.59%
	Chemicals	3.00%	2.72%	2.23%	2.07%	2.50%
	GAS	4.09%	-0.51%	-0.03%	-0.13%	0.84%
	Mining	2.78%	0.61%	2.73%	2.78%	2.22%
	Cement	2.16%	-0.83%	-1.38%	0.04%	-0.01%
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	-1.13%
	Oilsands	14.99%	8.87%	1.62%	0.00%	6.20%
	Other Manuf	0.51%	0.00%	0.00%	0.02%	0.13%
	Pulp and Paper	1.25%	1.24%	-0.99%	1.15%	0.66%
	Oil refining	-1.50%	0.10%	4.35%	0.65%	0.88%
BASE_8	EPG-COAL	1.57%	4.53%	-0.14%	-0.14%	1.44%
	EPG-GAS	6.52%	-5.24%	1.53%	8.35%	2.65%
	Chemicals	3.00%	2.72%	3.38%	2.76%	2.96%
	GAS	4.09%	-0.51%	-0.03%	-0.13%	0.84%
	Mining	2.78%	1.98%	2.48%	2.54%	2.44%
	Cement	2.16%	1.29%	-0.29%	1.30%	1.11%
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	-1.13%
	Oilsands	7.85%	12.13%	-6.02%	11.56%	6.11%
	Other Manuf	0.70%	0.57%	0.53%	0.52%	0.58%
	Pulp and Paper	1.25%	1.24%	1.12%	1.15%	1.19%
	Oil refining	-1.13%	0.60%	4.62%	0.54%	1.14%
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	EPG-GAS	7.45%	-3.99%	-1.68%	9.07%	2.56%
	Chemicals	3.00%	2.72%	3.38%	2.76%	2.96%
	GAS	4.09%	-0.51%	-0.03%	-0.13%	0.84%
	Mining	2.78%	1.98%	2.48%	2.54%	2.44%
	Cement	2.16%	1.29%	-0.29%	1.30%	1.11%
	Oil Conventional	-1.04%	-0.89%	-0.64%	-1.92%	-1.13%
	Oilsands	7.84%	12.14%	-6.02%	11.56%	6.11%
	Other Manuf	0.70%	0.57%	0.53%	0.52%	0.58%
	Pulp and Paper	1.25%	1.24%	1.12%	1.15%	1.19%
	Oil refining	-1.53%	0.37%	4.35%	0.45%	0.89%

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- The output of Oil sands in BASE_8 and in CASE 8 is severely lower than that in the BASE case or in Case 7 in 2010 and 2015, but gets back to the same level in 2020. All other sectoral outputs are unaffected both in Base 8 and in Case 8. Table 7 shows the amounts of bitumen and synthetic oil in all cases.
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Table IV.7. Oil production

PJ/yr		2000	2005	2010	2015	2020
BASE and Case 7	Bitumen	1446	2898	4433	4805	4805
	Conv oil	2132	2023	1934	1873	1700
BASE 8 and Case 8	Bitumen	1467	2139	3794	2781	4805
	Conv oil	2132	2023	1934	1873	1700

Table 8: Profit changes relative to Base, before and after paying for permits

		Case 7	Case 8
EPG coal	profit	-189	-1284
	permit cost	415	318
	net profit	**-604**	**-1602**
EPG gas	profit	-74	-269
	permit cost	34	18
	net profit	**-108**	**-287**
EPG noncov	profit	-44	-43
	permit cost	0	0
	net profit	**-44**	**-43**
GAS	profit	-80	344
	permit cost	-55	-85
	net profit	**-25**	**429**
CHEMICALS	profit	82	101
	permit cost	57	25
	net profit	**25**	**76**
CEMENT	profit	18	14
	permit cost	10	7
	net profit	**8**	**7**
MINING	profit	23	26
	permit cost	3	5
	net profit	**20**	**21**
P&P	profit	250	280
	permit cost	17	24
	net profit	**233**	**256**
OTH INDUSTRY	profit	19	53
	permit cost	-46	-29
	net profit	**64**	**82**
CONV OIL	profit	110	196
	permit cost	26	3
	net profit	**84**	**193**
OIL REFINING	profit	221	302
	permit cost	34	17
	net profit	**187**	**285**
OIL SANDS	profit	64	64
	permit cost	302	126
	net profit	**-238**	**-62**
Wood, prod	profit	0	0
	permit cost	0	0
	net profit	**-0.2**	**-0.1**
Total	profit	400	-214
	permit cost	798	428
	net profit	**-398**	**-643**

Note: profits changes are calculated relative to BASE for Case 7, and relative to BASE 8 for Case 8

Commentary

- The net profit of the Gas sector is much larger in Case 8 than Case 7, mainly due to the increase in export price.
- The changes in profits of the two EPG subsectors (Coal and Gas) are even more negative in Case 8 compared to Case 7. This is due to a drop in electricity prices, which occurs as early as 2005 and persists until 2015 in case 8 (see table 10). EPG-coal is most severely affected as it represents the larger portion of the sector, and because when emissions are capped, some electricity switches to gas (see table IV.9).
- Other sectors have profit changes in Case 8 that are not very different from those in Case 7.

Table IV.9. Electricity generation

Scenario	TWh/yr	2000	2005	2010	2015	2020
BASE	ELE (BIO)	0.4	0	0	0.9	1.4
BASE	ELE (COAL)	44.1	46.5	55.6	59	58.6
BASE	ELE (GAS)	12.5	19.8	15.4	16.8	19.9
BASE	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
BASE	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
BASE	Total	**59.5**	**68.8**	**73.6**	**79.3**	**82.5**
Case 7	ELE (BIO)	0.4	0	0.1	0.1	0.1
Case 7	ELE (COAL)	44.1	47.7	53.8	54.6	54.2
Case 7	ELE (GAS)	12.3	18.5	15.5	20.3	24.8
Case 7	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
Case 7	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
Case 7	Total	**59.3**	**68.7**	**72**	**77.5**	**81.6**
BASE_8	ELE (BIO)	0.4	0.4	0	0.4	0.4
BASE_8	ELE (COAL)	44.1	47.7	59.5	59	58.6
BASE_8	ELE (GAS)	12	16.5	12.6	13.6	20.3
BASE_8	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
BASE_8	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
BASE_8	Total	**59**	**67**	**74.6**	**75.6**	**81.9**
Case 8	ELE (BIO)	0.4	0	0.1	0.1	0.1
Case 8	ELE (COAL)	44.1	47.7	55	59	58.6
Case 8	ELE (GAS)	12.2	17.4	14.2	13.1	20.1
Case 8	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
Case 8	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
Case 8	Total	**59.2**	**67.6**	**71.8**	**74.7**	**81.4**

Table 8: Profit changes relative to Base, before and after paying for permits

		Case 7	Case 8
EPG coal	profit	-189	-1284
	permit cost	415	318
	net profit	**-604**	**-1602**
EPG gas	profit	-74	-269
	permit cost	34	18
	net profit	**-108**	**-287**
EPG noncov	profit	-44	-43
	permit cost	0	0
	net profit	**-44**	**-43**
GAS	profit	-80	344
	permit cost	-55	-85
	net profit	**-25**	**429**
CHEMICALS	profit	82	101
	permit cost	57	25
	net profit	**25**	**76**
CEMENT	profit	18	14
	permit cost	10	7
	net profit	**8**	**7**
MINING	profit	23	26
	permit cost	3	5
	net profit	**20**	**21**
P&P	profit	250	280
	permit cost	17	24
	net profit	**233**	**256**
OTH INDUSTRY	profit	19	53
	permit cost	-46	-29
	net profit	**64**	**82**
CONV OIL	profit	110	196
	permit cost	26	3
	net profit	**84**	**193**
OIL REFINING	profit	221	302
	permit cost	34	17
	net profit	**187**	**285**
OIL SANDS	profit	64	64
	permit cost	302	126
	net profit	**-238**	**-62**
Wood, prod	profit	0	0
	permit cost	0	0
	net profit	**-0.2**	**-0.1**
Total	profit	400	-214
	permit cost	798	428
	net profit	**-398**	**-643**

Note: profits changes are calculated relative to BASE for Case 7, and relative to BASE 8 for Case 8

Commentary

- The net profit of the Gas sector is much larger in Case 8 than Case 7, mainly due to the increase in export price.
- The changes in profits of the two EPG subsectors (Coal and Gas) are even more negative in Case 8 compared to Case 7. This is due to a drop in electricity prices, which occurs as early as 2005 and persists until 2015 in case 8 (see table 10). EPG-coal is most severely affected as it represents the larger portion of the sector, and because when emissions are capped, some electricity switches to gas (see table IV.9).
- Other sectors have profit changes in Case 8 that are not very different from those in Case 7.

Table IV.9. Electricity generation

Scenario	TWh/yr	2000	2005	2010	2015	2020
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BASE	Total	**59.5**	**68.8**	**73.6**	**79.3**	**82.5**
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Case 7	ELE (COAL)	44.1	47.7	53.8	54.6	54.2
Case 7	ELE (GAS)	12.3	18.5	15.5	20.3	24.8
Case 7	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
Case 7	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
Case 7	Total	**59.3**	**68.7**	**72**	**77.5**	**81.6**
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BASE_8	ELE (COAL)	44.1	47.7	59.5	59	58.6
BASE_8	ELE (GAS)	12	16.5	12.6	13.6	20.3
BASE_8	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
BASE_8	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
BASE_8	Total	**59**	**67**	**74.6**	**75.6**	**81.9**
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Case 8	ELE (COAL)	44.1	47.7	55	59	58.6
Case 8	ELE (GAS)	12.2	17.4	14.2	13.1	20.1
Case 8	ELE (HYD)	2.4	2.4	2.4	2.4	2.4
Case 8	ELE (WIND)	0.1	0.1	0.1	0.1	0.1
Case 8	Total	**59.2**	**67.6**	**71.8**	**74.7**	**81.4**

Commentary

- Total generation is slightly lower in Case 8 than in case 7. This is because electricity prices are somewhat higher due to the increase in gas prices (table IV.10).
- Gas fired generation is only marginally larger in Case 8 relative to Base 8 (whereas Case 7 had a significantly larger gas fired production than Base). Again, the cause is the high price of gas, which keeps coal-fired generation preponderant in all cases shown.

Table IV.10. Electricity prices

cents/kWh	2005	2010	2015	2020
BASE	3.9	3.6	3.7	3.4
Case 7	3.9	3.4	3.4	3.5
zBASE_8	5.1	4.0	4.4	4.1
zCase 8	4.6	3.8	4.0	4.2

Commentary

- Total generation is slightly lower in Case 8 than in case 7. This is because electricity prices are somewhat higher due to the increase in gas prices (table IV.10).
- Gas fired generation is only marginally larger in Case 8 relative to Base 8 (whereas Case 7 had a significantly larger gas fired production than Base). Again, the cause is the high price of gas, which keeps coal-fired generation preponderant in all cases shown.

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BASE	3.9	3.6	3.7	3.4
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Alberta Environment Emission Trading Project

Major Feasibility Study

Preliminary Analysis & Discussion Document

APPENDIX B:

Costs of Technologies to Reduce NOx and SOx Emissions From Industrial and Electric Power Generation Sources in Alberta

March 2003

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Alberta Environment

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1. Introduction

1.1 Purpose

The purpose of this Appendix is to provide an analysis of emission reduction technologies and related costs across the major industrial and electric power generation sectors in the province of Alberta. The Appendix first describes the methodologies applied to estimate the costs of emission reduction technologies among the facilities in Alberta, and then presents the range of cost results for the various applicable technologies. For each pollutant, various technology options and their costs are analyzed for emitting sources. The reduction technology costing results serve as an important input to the modelling of emission reduction costs and the assessment of the feasibility of an emissions trading system in Alberta.

An important criterion for assessing the feasibility of an emission trading system (among the other criteria applied as part of this study) is the degree to which potential trading participants have variations in emission abatement costs. Participants that have low relative costs will be able to apply technologies to reduce emissions more and sell excess reductions to participants that face higher costs. The sale of allowances/credits will offset (in whole or in part) the costs of applying the abatement technologies, as well as serve to reduce the total costs of abatement among all participants.

Estimating the costs faced by major trading participants also allows for the determination of which participants are likely to apply technologies to reduce emissions and which are likely to purchase allowances/credits (instead of reducing at least some of their emissions). This information yields an understanding of the costs to groups of participants (e.g. sectors). It can also assist in the understanding of regional emission effects resulting from a trading program, since the costs were prepared for specific facilities in known locations. In addition, the determination of costs for each participant is necessary in developing the total cumulative costs for the province, given sectoral, regional (for Alberta's 19 census regions) and provincial emission reduction objectives.

- The identification of applicable technologies and the estimates of capital and operating costs that are specific to the sector facilities in Alberta are critical parts of the Major Feasibility Study. The assessment of the feasibility of emissions trading in Alberta, as well as the assessment of various emission allocation schemes, needed to take into account the costs of reducing emissions from Alberta's unique facilities and equipment sources.

1.2 Scope

The focus of the analysis in this Appendix, in terms of pollutants, is on SO_x and NO_x emissions. Analysis of GHG emission reduction actions for Alberta's economy has been previously undertaken by the National Climate Change Process (NCCP) and is not repeated in this Appendix.

A total of approximately 300 individual technology cost estimates have been prepared and used as input into MARKAL. For many emission sources, cost estimates were developed for multiple reduction technology options. These options spanned the range of possible reduction levels from low- 10% to very high - 95%+. The individual cost results presented in this Appendix are mostly shown as ranges to protect the confidentiality of information pertinent to specific facilities in Alberta.

1.3 Coverage of Costing Analysis

A total of 7 sectors, which are outlined in the Table 1, were analysed during the course of this study. The focus of this study was on large facilities that contribute most significantly to NO_x and SO_x emissions in Alberta and would therefore most logically be potential participants in an emissions trading program in the future. Practically all emission sources among the facilities in the electric power generating sector, pulp and paper (kraft mills) sector, panel board industry and cement sector have been analyzed. For the chemicals sector, costs were prepared for approximately 75% of the emission sources.[1] Costs were not developed for many small facilities or equipment sources for which data was not available. For the upstream oil and gas and wood products/lumber sectors analysis was undertaken at the source category level, since there were emission sources among these sectors for which sufficient information to support equipment-specific costing analysis was not available.

As can be seen in the Table below, this study addressed facilities and sectors, which represent 99% and 98% of total industrial/electric power generation emissions of SO_x and NO_x, respectively in Alberta. It should be kept in mind that in most sectors, abatement costs were developed for the majority, but not necessarily all, emitting equipment within the covered sectors. However, the emissions from these sources represent a very minor portion of total Alberta emissions and should not affect the overall results of the study. GHG emissions released by the industrial/electric power generating sectors covered in the analysis represent 97% of total industrial/electric power generating GHG emissions in Alberta (and approximately 74% of total Alberta emissions).

---

[1] Coverage of 75% based on portion of large facility point sources - Chemical sector area sources (i.e., hundreds of small facilities) excluded.

Table 1: 2010 Covered Emissions from Industrial and Electric Power Generation Sectors in Alberta

Sector	SOx	NOx	GHG
	(kilotonnes)		(Megatonnes)
Total Alberta Emissions (natural and anthropogenic)	561	851	256
Conventional oil & gas	229	372	51
Oil sands plants	169	157	57
Electricity generation	129	98	58
Petroleum refineries	12	5	6
Cement	3	6	2
Chemicals	-	19	14
Pulp and paper	2	4	1
Wood products	-	6	-
Total large industrial and EPG sources	25	1518	445
Share of total industrial and EPG emissions	99%	98%	97%
Share of total Alberta emissions (natural and anthropogenic)	97%	78%	74%

Note: In some sectors only certain segments were analyzed (e.g. only kraft mills in pulp and paper sector).
Source: MARKAL output for covered emissions used in this study. May not add due to rounding.

1.4 Structure of the Rest of This Appendix

There are 8 main chapters to the Appendix and three additional sections (chapters 10 to 12). Chapter 2 describes the methodologies applied in developing cost estimates for emission reduction technologies. Chapters 3 to 8 are each focused on a specific sector. The chapters are:

Chapter 2	Methodologies for Estimating Costs
Chapter 3	Electric Power Generation
Chapter 4	Chemicals/Petrochemicals
Chapter 5	Lumber and Allied Wood Products
Chapter 6	Pulp and Paper
Chapter 7	Cement
Chapter 8	Petroleum Refining
Chapter 9	Upstream Oil & Gas
Chapter 10	Bibliography
Chapter 11	Industry Contacts
Chapter 12	Crosscutting Technologies

The sector chapters (3 to 9) follow a common structure. An introduction to the sector in Alberta is provided followed by an overview of processes employed, energy used and emissions types and quantities. A description of technologies/practices that can be employed to control emissions is then provided. The range of costs that would be incurred to achieve various levels of emission reductions through the utilization of these control technologies is outlined.

Chapter 10 contains the bibliography for the study, outlining the literature sources, websites, databases and models that were consulted. Chapter 11 provides a listing of the companies and their representatives that were interviewed. Chapter 12 provides descriptions on cross-cutting NO_x, SO_x or GHG emission control technologies that can generally be applied across each of the sectors analyzed in this study.

2. Methodologies for Estimating Costs

2.1 Overview

The objective of the costing analysis was to develop capital and annual operating cost estimates for suitable technologies that could achieve low (e.g. 5 to 30%), medium (30 to 70%) and high (70 to 100%) levels of reduction from current emission levels. Cost estimates for these different reduction levels were developed at the most detailed level possible, subject to available information. This was either at the emitting equipment level (e.g. specific boilers, furnaces, kilns at facilities), facility level or at the emission source category level (e.g. group of mobile equipment, group of similar compressors).

A variety of approaches can be applied to generate cost estimates for technologies to reduce NO_x, SO_x and GHG emissions for industrial facilities. It is preferable to obtain estimates from industrial facilities that have prepared costs of emission reductions by applying detailed engineering studies. Most emitters contacted in this study had not estimated the cost of technology options for further reductions, since their focus is on existing regulatory requirements. Only about a dozen companies of the 58 companies contacted in this study had prepared some cost estimates for further reductions. These were incorporated in results. Companies contacted are listed below (see subsection *Direct Contact With Industry).* For other facilities and emission source categories, alternative costing approaches were applied to meet the objectives of the project.

Different alternative costing approaches were necessary due to the unique nature of some of the processes in various sectors, as well as issues with respect to availability and variability of process and emissions data. The approaches applied were appropriate to generate the accuracy required. The major costing approaches applied across the 7 sectors analyzed in this study are outlined in the table below. A brief description is then provided on the various approaches that were applied.

Table 2: Costing Approaches Applied to Sectors Analyzed in this Study

Sector	Costing Approaches Applied
Electric Power	• Direct contact with industry. • US EPA literature sources. • Modified US EPA control cost models applied at the unit level.
Chemicals	• Direct contact with industry. • Direct contact with technology suppliers. • US EPA literature sources. • Modified US EPA control cost models to emitting equipment.
Lumber and Allied Wood Products	• Direct contact with industry. • Modified US EPA control cost models.
Pulp and Paper	• Direct contact with industry. • Literature sources completed for: (i) Environment Canada; and (ii) European Commission – Institute for Prospective Technological Studies
Cement	• Direct contact with industry. • Studies completed for: (i) U.S. EPA; (ii) Cembureau (European Cement Association); (iii) Portland Cement Association; and (iv) European Commission – Institute for Prospective Technological Studies.
Upstream Oil & Gas (includes Oil Sands)	• Literature sources. • Cost models (Clearstone Engineering) • Modified US EPA control cost models. • Direct contact with industry (oil sands, and some gas processing facilities).
Petroleum Refining	• Modified US EPA control cost models. • Literature sources completed for: (i) Ontario Ministry of Environment; and (ii) European Commission – Institute for Prospective Technological Studies.

2.2 Direct Contact with Industry

Cheminfo Services and Clearstone Engineering contacted industrial facilities and conducted the technology costing analysis. These firms applied their expertise in the various sectors as shown in the Table below.

Table 3: Alberta Facilities Interviewed During the Study

Sector	Number of Facilities Contacted	Primary Responsible for Industry Contact and Costing	Estimated Coverage (Based on Production or Emissions)
Electric Power Generation	5	Cheminfo	100% (coal fired power)
Chemicals/Petrochemicals	16	Cheminfo	70%
Lumber and Allied Wood Products*	19	Cheminfo	80%+
Pulp and Paper (Kraft Pulping)	4	Cheminfo	100% (kraft mills)
Cement	2	Cheminfo	100%
Upstream Oil & Gas, Oil Sands	5 2	Clearstone Engineering	Minor portion of facilities Major (Existing facilities)
Petroleum Refineries**	5	Clearstone Engineering#	Major
Total	58		

Notes: In several instances, multiple interviews at some facilities were conducted in order to gather the information required for the analysis. * Includes all 6 panel board mills and 13 sawmills. # With assistance from Cheminfo Services. ** Includes Alcan Inc. carbon plant.

The project team contacted major industrial facilities, except in sectors where the number of facilities or emitting sources made individual contacts unfeasible. The Upstream Oil and Gas sector and the Lumber and Allied Wood Products sector include many sources that could not be individually analyzed. For these areas, only a small portion of facilities were contacted and the costing analysis was applied to groups of similar facilities and emitting equipment. A similar approach was taken with petroleum refineries. Detailed data for the many equipment sources were not developed. The analysis of groups of similar facilities and sources of emissions provides an of costs for emission reductions that are similar to estimates found in the literature.

The purpose of contacting industrial facilities was to obtain industry-based information on emission sources as well as applicable control technologies and their costs. Most facilities contacted were able to provide an allocation of emissions among the various emitting processes at their facility, which assisted in determining the cost-effectiveness of various abatement options. Some facility contacts were able to identify emission control options that could be used to achieve emission reductions at their facilities. Some of these also provided information on the costs of these abatement options. This information was directly incorporated. In several instances, the control costs that were estimated for specific facilities were vetted with the contacts that had been established for those facilities. Costs for each of the Electric Power Generating facilities were vetted with each of the major companies.

Cost estimates were directly received from some companies or were available in reports that were sufficiently detailed with respect to specific facilities and technology reduction levels of interest (i.e., low, medium and high). A number of companies provided specific cost input. These were:

- The major companies representing the existing coal and gas-fired facilities in the Electric Power Generating sector: TransAtla, EPCOR, ATCO Power;
- Seven chemical plants provided partial cost data: Nova Chemicals, Dow Chemicals, Orica, Marsulex, Sherritt, Canadian Fertilizers, Shell (Styrene plant);
- One oil sands / upgrading facility: Syncrude;
- One carbon plant: Alcan Inc. (classified with Petroleum products sector); and
- One cement company: Lafarge (one NOx technology).

The remaining companies contacted had not prepared detailed or sufficiently accurate cost estimates to further address pollutants of interest. In these cases, the consultants applied standard cost functions (or models) with some operating parameters as provided by industry to develop cost estimates.

2.3 Modified U.S. EPA Control Cost Models

Where facilities had not prepared cost estimates for further emission reduction cases, data was requested and obtained which allowed the consultants to estimate costs using standard cost models. Cost functions or models developed for the U.S. EPA, during the 1990s, were modified and applied in order to develop cost estimates for steam boilers, furnaces, process heaters and other SOx and NOx emission sources. These modified models are based on the following original models:

1. Integrated Air Pollution Control System Program (IAPCS version 5a), WP5.x User's Manual **(NGR, LNB, OFA, LEA, LNCFS and LIMB)**
   [pdf file 165 kb: http://www.epa.gov/ttn/catc/dir1/iapcswp5.zip]
   Volume 2: Technical Documentation contains the control option equations & parameters.

2. OAQPS Control Cost Manual - Sixth Edition (EPA 452/B-02-001) Entire Document (All Chapters Currently Available) **(SCR and SNCR)**
   [pdf file 2521 kb: http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf]
   Sections 4 and 5 deal with NO_x and SO_2 control options.

3. Coal Utility Environmental Cost (CUECost) Model Version 1.0 (Software & MS Word Manual **(LSFO and LSD)**
   [3,020 kB zip file: http://www.epa.gov/ttn/catc/dir1/cuecostw.zip]

Since most of the U.S. EPA's focus in the 1990's was on coal combustion emissions, some of the cost algorithms were originally designed for application to coal-fired utility boilers. While these cost models were applied for coal-fired boilers in this study, they were also applied for combustion equipment using biomass, spent liquor (i.e., at pulp mills), sludges, and natural gas. Suitable modifications were incorporated to account for the different fuels. The applicability of these models in estimating NOx and SOx emission reduction costs for various combustion devices using alternative fuels (e.g. oils, biomass and natural gas) had been previously subjected to an external quality assurance and quality control process, which determined them accurate for estimating abatement costs.

2.4 Literature Sources

Literature sources on emission reduction costs in the various sectors served at least two purposes in this project. That is, they provided:

- typical costs for facilities or processes. Typical costs from similar facilities were applied to Alberta facilities where there was insufficient detailed information to estimate costs using models or other means; and
- points of reference against which costs results for Alberta facilities prepared in this analysis were compared to ensure reasonableness.

Information was not readily available to estimate costs from emitting equipment within some facilities contacted. For these emission sources, cost estimates available from literature sources or previous work of the consulting team on similar sources (outside of Alberta) within the same sector were applied. Many literature sources were reviewed to facilitate the estimation of costs of emission reduction among Alberta industrial facilities.

Some of most important literature sources among the many (see *Bibliography*) were:

- BREF documents published by the European Integrated Pollution Prevention and Control Bureau;
- Alternative Control Techniques (ACT) documents (costs of NO_x emission reduction technologies) published by the U.S. Environmental Protection Agency; and
- Miscellaneous reports published by government agencies and industry associations.

The European Integrated Pollution Prevention and Control (IPCC) Bureau exists to catalyse the exchange of technical information on best available techniques to reduce emissions. The Bureau has created a set of technical reference documents referred to as BREFs, to assist European Community Member States in determining conditions for IPPC permits. IPPC applies to a wide range of industrial activities and the objective of the information exchange exercise is to facilitate the efficient implementation of the directive across the European Union. The BREFs inform decision-makers on what may be technically and economically available to industry in order to improve their environmental performance and consequently improve the whole environment.[2]

The U.S. Environmental Protection Agency has published a series of reports on the alternative control techniques available to reduce NO_x emissions from various industrial sectors. These documents typically have detailed cost information (capital, operating) on many NO_x emission reduction technologies as well as the emission reduction potential of those technologies. In addition, in some instances the costs associated with different sized emission control technologies are also provided.

There were several other reports that were used to assist in estimating costs of NO_x, SO_x and/or GHG emission reductions at Alberta industrial facilities. Reports prepared for Environment Canada, the Ontario Ministry of the Environment, the Portland Cement Association (U.S.) and Cembureau (European cement association) were utilised.

A listing of all studies and databases consulted in the preparation of this Appendix is provided in the *Bibliography*.

2.5 Assumptions

Various assumptions were applied to develop the cost estimates for technologies. There are many technical assumptions embedded in the costing models applied, and interested readers should refer to the documentation accompanying the models. There are also source-specific assumptions that have been applied. Reasonable simplifying assumptions were applied to estimate process or emission parameters at facilities or sources where information was not available. For example, in some cases assumptions were made with regard to: stack gas flow rates (e.g. flow rates were related to fuel consumption rates); stack temperatures (assumed that similar equipment have similar temperatures); allocations of total facility emissions to specific equipment; and anticipated reduction levels achievable by the technology. It is not possible in the Appendix to describe all of the individual assumptions applied to each of the emitting sources. Some key assumptions are described in the sector chapters that follow. Assumed energy prices and other broad assumptions applied to all of the costing analysis are:

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[2] European Integrated Pollution Prevention and Control (IPPC) Bureau http://eippcb.jrc.es/

- Natural gas price at 4 $/GJ;
- Electricity price at 4.8 cents/kWh;
- Coal price at 0.75 $/GJ;
- Cost of capital - 10% per annum; and
- All capital costs amortized over 20 years.

While the above prices were adopted to generate initial results for this Appendix, these prices are the not the same prices that were ultimately derived by MARKAL (see explanation below). Cost estimates based on these assumptions were provided to some industry sources (e.g. EPG companies and some chemical companies) as a point of reference in the process of obtaining their feedback on the reasonableness of the estimated costs prepared for their facilities. Using these assumptions, costs estimates could also be compared with estimates from the literature, as well as some estimates prepared by Alberta Environment.

The facility- and equipment-specific results provided as input to MARKAL were the capital costs of technologies and a portion of the annual operating costs (i.e., all annual operating costs excluding energy costs). For each technology the anticipated level of emission reduction was provided for the target pollutant that the technology is designed to address. Where available, estimates of the increases or decreases of other pollutants related to operation of the abatement technology were also provided. For example, at facilities generating electricity from coal, SOx scrubbing technologies can reduce a portion of mercury emissions. Annual energy costs (e.g. fuels and electricity) were not included as part of the operating costs input provided to MARKAL (although they were calculated and shown in the results in this Appendix using the above prices). However, energy consumption (e.g. kWh, gigajoules of fuel) associated with the reduction technologies was provided to allow MARKAL to apply endogenously-calculated energy prices (e.g. for electricity, natural gas, etc.) to estimate the total annual operating costs of the technology options. The energy consumption information was also applied by MARKAL to estimate the additional cumulative energy consumed and that would need to be supplied in the province, as a result of emission reduction technology adoption by the facilities in Alberta.

2.6 Presentation of Results

The cost estimates are presented as ranges for the multitude (i.e., hundreds) of technology options that can achieve different levels of emission reductions. The final section in each chapter discusses the potential for accurately measuring and monitoring emissions and emission reductions in order to support participation in an emissions trading system.

The results are presented as cost ranges for each technology option for all sectors since it is not feasible to develop technology cost curves for all pollutants for each sector. Cost curves can be misleading because they do not take into the account the complexities of technology choices and interactions between the reduction options. For example, some GHG options may mitigate the requirement for SOx technologies. In effect a GHG technology becomes a SOx reduction option, which should be included as part of the cost curve. However, in a multi-pollutant analysis such as this, the GHG technology could also have impacts on NOx and mercury, such that the cost curve would not accurately reflect the costs to the sector at each level of SOx reduction. The ranges show costs for technologies applied for similar source categories (e.g. boilers, furnaces, etc.) within each sector for each pollutant (NOx and SOx). Company- and facility-specific results are not presented in order to respect confidentiality concerns.

Technology combinations, interactions and their costs are handled by MARKAL as part of the next step in the analytical process (see Appendix A).

2.6.1 Parameters Affecting Cost Estimates

In order to develop cost estimates for reducing emissions from specific equipment, data characterizing the emitting equipment, the emissions and the emitting process are required. The data serve as input parameters in cost functions (or correlations) that yield estimates of capital and operating costs to achieve the reductions. Cost functions are an alternative to expensive engineering studies when only approximate estimates are required, as in this study. Cost functions are usually based on the following input data:

- size of the process equipment (e.g. size or input or output capacity of equipment);
- energy consumption rate and/or mass flow rates through emitting equipment;
- mass quantity of emissions per unit of time to be addressed;
- volumetric flow rate of exhaust stack gas and pollutant concentrations in gas (or concentration of pollutant in gas stream being treated);
- stack gas temperatures (and need to heat exhaust stream to be treated, with some technologies); and
- unique features of stream being treated (e.g. concentration of substances that may affect emission reduction technology).

Typically the individual costs for a large population of emitting sources within a sector will feature a small portion of emitting equipment where the costs of reductions are at the high and low ends of the range. The majority of equipment will have emission reduction costs around the mean. Relative differences in the above parameters result in cost differences between emitting equipment. For example, one source may be small in size, but have large annual emissions in a high concentration gas stream. Another source may be large in size but have a low quantity of emissions in a dilute gas stream. The capital and annual operating costs for these sources will therefore be quite different, for a common level of reduction. In addition to these parameters, there are unique equipment- or site-specific factors (e.g. lack of physical space to install reduction technology) that can contribute to differences in costs of emissions reductions. Furthermore, some equipment may already possess control systems (e.g. low-NOx burners), such that the costs of additional technologies (e.g. selective catalytic reduction) for these sources will be higher compared to a similar source that does not already possess control systems.

These factors can differ between facilities that make the same or very similar set of products. Reasons for this include:

- differences in energy or raw material efficiency (e.g. older units are usually less efficient);
- fuels used (e.g. some plants use natural gas, others coal);
- fuel content (fuels have different nitrogen and sulphur levels);
- theoretical capacity and actual production, and ratio between the two (capital costs are related to capacity, while operating costs are more related to emissions associated with actual production);
- unique nature or configuration of the facility (e.g. space limitations); and
- operational and environmental care.

All of these factors contribute to the wide range of costs in Alberta's sectors, as shown in the results presented in subsequent sections of this Appendix.

3. Electric Power Generation

3.1 Industry Overview

Alberta's Electric Power Generation (EPG) sector (SIC 49, NAICS 22) consists of approximately 60 facilities that generate electricity using coal, natural gas, and hydro energy sources. Most of the generation capacity is located in the Edmonton/Wabamun/Fort-Saskatchewan area (census region 11). TransAlta, EPCOR and ATCO Power are the major generators, operating 9 facilities, with a total of 29 units. These facilities account for over 80% of the electricity generation, over 99% of SOx emissions, 85% of NOx emissions and 90% of GHG emissions associated with electricity generation in the province. The estimated range of costs for technologies that can address these emissions are provided in Table 9. Not all of the technologies shown in the tables below are applicable to all units in the sector.

Table 4: Major EPG Facilities Covered in this Analysis

Company / Facility Name	Location	Census Region	Fuel	Current Capacity (Megawatt - MW)
TransAlta				
Sundance Units (6 units)	Sundance	11	Coal	2112
Wabamun Units (3 units)	Wabamun	11	Coal	444
Keephills Units (2 units)	Keephills	11	Coal	800
EPCOR				
Genesee (2 units)	Edmonton	11	Coal	820
Clover Bar (4 units)	Edmonton	11	Gas	660
Rossdale (5 units)	Edmonton	11	Gas	225
ATCO				
Sheerness (2 units) (Co-owned with TransAlta)	Hanna	4	Coal	800
Battle River (3 units)	Forestburg	7	Coal	675
H.R. Milner (1 unit)	Grande Cache	19	Coal	150

Sources for current capacities: Input from TransAlta, EPCOR, ATCO.

Companies operating in the industrial sectors, such as pulp and paper, oil sands and chemicals, also generate electricity. The generated electricity can be used for internal purposes and/or sold. These generating units can use excess heat to make steam (e.g. from hot process flue gases) to drive on-site generators, or possess natural gas systems -

usually combined cycle - and act as user-hosts for steam generated by the electricity/steam-producing units. Some generating facilities in these sectors are owned and/or operated in part by companies in the EPG sector.

3.1.1 Power Purchase Agreements (PPA)

Power Purchase Agreements (PPA) are an important feature of Alberta's deregulated electricity market, which came into effect in January of 2001. These agreements are between electricity generators and wholesalers. Some companies that generate electricity are vertically integrated in the industry, purchasing and reselling power. PPAs include contract terms for electricity exchange values and quantities based on anticipated agreed-upon costs, and can be related to specific units for specific periods. This costing analysis does not address any potential contractual or economic implications associated with PPAs. Economic issues related to reducing emissions in context of existing PPAs have been recently studied[3].

3.2 Processes and Energy Use

Electricity can be generated from a variety of energy forms, including fossil fuels, radioactive materials, biomass, organic solid waste, etc.); steam (as an energy intermediate); moving water, wind and sunlight. Most of the electricity generated in Alberta is based on simple cycle coal-fired facilities. Natural gas-based systems have recently increased their portion of the total electricity generated in the province. Only thermal and combustion turbine systems based on coal and/or natural gas are analyzed in this section. General descriptions of these systems are provided below.

Thermal electricity involves the combustion of fuels for the heating of water and the generation of high pressure steam as an energy intermediate. The most common fuels used are coal, natural gas, fuel oils, or biomass. The high-pressure steam turns a steam turbine connected to the generator. Simple-cycle systems involve the simple conversion of fuel energy to steam (via combustion gases) to electricity (via mechanical energy) and tend to have electrical efficiencies of 30 to 35%. That is, 30 to 35 energy units of electricity are generated from 100 energy units of fuel/energy input.

Table 5: Trends in Energy Sources for Electric Power Generation in Alberta

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[3] Joseph Doucet Economic Consulting Inc., *Power Purchase Arrangements, Wholesale Market Organization and Air Emission Management Options,* Submitted to the Clean Air Strategic Alliance (CASA) Electricity Project Team, November 26, 2002

(% of total annual generation)

	1990	1995	2000
	(Terawatt-Hours- TWH)		
Total estimated generation	42	51	59
Energy Source (% of total)			
Coal	81%	81%	74%
Natural gas (simple and combined cycle)	13%	12%	19%
Hydro	5%	4%	3%
Biomass	0%	1%	1%
Oils, wind, other fuels	0%	2%	3%

Sources: Analysis and Modelling Group/Natural Resources Canada for 1990 and 1995[4] Statistics Canada for 2000.[5]
Rounded - zero percent means less than 0.5% and may not be zero.
Includes generation from EPG and other sectors. Percent of totals are not equal to percent of total energy input, due to different efficiencies of generating systems.
Numbers in the above table may be slightly different than MARKAL Base Case results generated in this project.

Combustion turbine systems use the same direct-conversion concept, but the mechanical energy is created in a gas turbine (turned directly by the hot combustion gases of the fuel burned). Natural gas is the most common fuel used in combustion turbines, but fuel oils can also be used.

There are variations in the types of generating systems where natural gas can be used. The following efficiencies (based on higher heating values) are typical for different natural gas based systems. These efficiencies are related only to the generation of electricity.

• Natural Gas Firing in Simple Cycle System:	34% on electricity
• Natural Gas Combined Cycle (NGCC):	50% on electricity
• Natural Gas Combined Cycle + waste heat utilization:	50% on electricity

For "Natural Gas Combined Cycle + waste heat utilization" the 50% efficiency relates to the generation of electricity, only. It does not reflect the overall efficiency of the system (energy out versus energy in) which could be higher (~60 to 80%). The exact efficiency of the system in reducing energy requirements and GHG emissions can be complex to estimate due to the need to determine the type of fuel eliminated as a result of the waste heat utilization (and associated emissions). Utilizing waste heat improves the efficiency of the system but does not reduce the amount of natural gas required to make the electricity or the emissions from the electricity facilities (versus not recovering the waste heat). The recovery of the heat serves to reduce emissions when considering the emission sources that the heat recovery would displace.

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[4] Analysis and Modelling Group/Natural Resources Canada for 1990 and 1995. *Canada's Emissions Outlook: An Update*, December 1999.

[5] Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada, 2000-IV*, Catalogue no. 57-003-XPB for 2000.

Integrated Gasification Combined Cycle (IGCC) systems are alternatives to the traditional simple cycle coal plants. In an IGCC system, part of the coal is converted into a gaseous fuel, which, when cleaned, is comparable to natural gas. The coal is converted into a gaseous form in an advanced gasifier before combustion. The hot gas is further cleaned by an advanced cleanup process before being burned in the gas turbine to generate electricity. Exhaust heat from the gas turbine is used to produce steam for a conventional steam turbine, resulting in the two cycles of electric power generation. IGCC power systems are typically considered to be capable of achieving efficiencies of up to 42 percent. Some designs in the development stage may increase this efficiency level. There are no IGCC plants in Alberta or in the rest of Canada.

IGCC systems can be constructed to achieve very low criteria air contaminant emission rates. In an IGCC system, close to 99% of the coal's sulphur needs to be removed. NOx can be reduced by over 90%, and GHG is reduced by 35% (due to efficiency gains versus simple cycle systems). The capital cost of such systems can be 1,200 $/kW, or more. The IGCC system is being demonstrated with a least a couple of installations in the United States.

3.3 Emission Sources

Flue gases from the boilers or turbines that combust the fossil fuels consumed in the process are the only significant source of emissions from EPG facilities. Potential emissions from the combustion process are vented through stacks (after the heat has been extracted), which in some cases receive flue gases from multiple adjacent units.

SOx and NOx emissions are the predominate criteria air contaminants associated with the Alberta EPG sector. SOx emissions result from the oxidation of sulphur contained in the coal combusted. The level of sulphur in the sub-bituminous coal used in Alberta is relatively low versus many other coals in North America). It typically ranges from 0.2 to 0.5% by weight. NOx is generated in the combustion process, with the source of nitrogen being the combustion air as well as some nitrogen contained in the fuel. Carbon dioxide (CO_2) is the predominant GHG emission, with negligible amounts of methane and nitrous oxide being emitted. Practically all of the carbon contained in the fuel is oxidized to CO_2, while a very small portion is released as CO, VOC or contained with the PM emissions. Coal is also the major source of mercury emitted by the sector.

Table 6: Example Emission Rates For Alberta EPG Facilities

(kg/MWh)

Substance	**Coal (Simple Cycle)**	**Natural Gas Simple Cycle**	**Natural Gas Combined Cycle**
Basis	**Current Alberta Average**	**Average of 2 Facilities**	**New NGCC: Meeting Alberta NOx Guidelines**
PMT	0.2	0.0	0.0
PM10	0.2	0.0	0.0
PM2.5	0.1	0.0	0.0
SOx	2.8	0.0	0.0
NOx	1.7	1.6	0.6
VOC	0.02	0.01	0.0
CO	0.2	0.2	0.1
GHG	1000	600	360 to 480
Mercury	0.000016	0.0000012	0.0000008

Note: Approximate to show range

Emission rates or intensities (which can be expressed as kg/megawatt-hour of electricity generated) vary by plant based on the types of fuels, fuel contents (e.g. for sulphur), operating efficiency (or heat rate), emission controls in-place, and other factors. Even for a given generating technology, emission rates can vary significantly. Some typical emission rates for coal and gas facilities in Alberta are shown below.

Table 7: Examples of High, Low Emission Rates for Coal Plants

(kg/MWh)

Substance	**Coal (Simple Cycle)**		
Basis	**Approximate Alberta Average**	**Example of High Rate of Emissions**	**Example of Low Rate of Emissions**
PMT	0.2	0.3	0.1
PM10	0.2	0.3	0.1
PM2.5	0.1	0.2	0.1
SOx	2.8	6	2
NOx	1.7	3	1.5
VOC	0.02	0.03	0.02
CO	0.2	0.3	0.1
GHG	980	1300	940
Total Hg	0.000016	0.00003	0.00002

Rounded. Note: There may be facilities or units within facilities that operate outside of the range shown. These are not examples of any specific facility in Alberta for each of the pollutant shown.

3.4 Reduction Technologies

Some units at facilities in Alberta's EPG sector have already adopted low-NOx burners or have implemented other systems (e.g. instrumentation, combustion air controls, operator care) to address a portion of their total potential NOx emissions. The exact effect of these technologies and practices versus potential uncontrolled NOx emissions (before these technologies or practices were adopted) is unknown. These technologies also improve the efficiency of the operations and thereby reduce energy consumption and emissions of SOx and GHGs. No end-of-pipe control technologies were identified to address potential SOx, mercury or GHG emissions among EPG facilities. The coal-fired EPG facilities covered in this study operated with electrostatic participators or baghouses to control potential PM emissions. These systems typically achieve over 98% reduction for PMT and PM10, but capture a lower portion of fine, i.e.PM2.5, emissions. Technologies and cost estimates took into consideration existing NOx and SOx technologies already in place.

There are a variety of technologies available to address NOx, SOx and GHG emissions. The potential emission reduction effectiveness (expressed as a percentage of uncontrolled emissions from simple cycle coal fired plants) of various technologies was provided by some Alberta companies contacted in this study. Where such input was not provided, literature sources were applied. Emission reduction effectiveness factors were checked with the major Alberta companies contacted in this study to ensure they would be suitable for their facilities.

Table 8: Identified Reduction Technologies for Coal-Based Power Plants

Primary SOx Technologies	**Acronym**	**SOx**	**NOx**	**CO_2**	**Mercury**
Dry lime scrubbing	DLS	90%		*(~1-2%)*	~9%
Limestone Scrubbing (Forced Oxidation)	LSFO	95%		*(~2-3%)*	~9%
Limestone Injection in Furnace With Activation Chamber	LIFAC	63%		*(~2-3%)*	6%
Lime Injection Multi-stage Burners	LIMB	55%		*(~2-3%)*	5%
Primary NOx Technologies					
Improved combustion air, instrumentation, operator care	IIOC		5-25%		
Low excess air	LEA		15%		
Over-fired air	OFA		25%		
Low NOx Concentric Firing Systems	LNCFS		25%		
Low NOx burners	LNB		30-41%		
Selective Non-Catalytic Reduction Technologies	SNCR		45%		
Natural gas reburn (related to 15% gas substitution)	NGR	15%	61%	~7%	14%
Selective catalytic reduction	SCR		70-85%		
Primarily GHG Technologies					
Natural gas substitution for coal (simple cycle)	NGSC	100%	19%	~45 to 50%	93%
Natural gas combined cycle	NGCC	100%	~50-70%	~66%	>95%
Integrated gas combined cycle	IGCC	99%	90%?	~20%	~20%
Amine scrubbing and storage	AS+S			>95%	
Capture and underground storage	US			>95%	

Note: Numbers in brackets means emissions increase.

3.5 Costs of Reduction Technologies

There is a wide range of estimated capital, operating and maintenance costs for addressing emissions among facilities and units in Alberta's EPG sector. Some of the major factors resulting in the wide range of estimates include differences in:

- size of facilities and related economies of scale for capital installations;
- rates of emissions;
- efficiency of units (i.e., heat rates);
- stack gas flow rates for each unit per unit of electricity generated;
- stack gas temperatures;
- space limitations at some facilities;
- ratio of capacity to actual average generation rates; and
- different reduction effectiveness estimated by companies for similar technologies.

Capital costs for addressing NOx and SOx emissions for this study were estimated on the basis that each unit in each facility would need to install reduction technologies to address emissions at all times of operation. That is, capital cost estimates are based on the size of the units (e.g. boiler sizes), maximum heat input rates, stack gas flow rates, etc. The relationship between the size of the units and stack gas flow rates strongly influence the unit capital costs (as expressed as $/kW). Operating and maintenance costs are largely influenced by the amount of emissions and stack gas flow rates. For some technologies, estimates of annual maintenance costs are based on the total capital costs. Therefore factors that affect capital costs can also affect the annual combined O&M cost estimates.

There are unique technical, space, infrastructure, and other features at some facilities that result in higher costs. For example, one company estimated that space restrictions at one of its facilities would result in at least an extra 20% higher capital cost for any emission control equipment installations.

Another source of variation in costs is related to the estimates provided by the EPG companies. Some companies used different methods to estimate capital and operating costs. Cost estimates have been reviewed with the major EPG companies, such that while there are differences between facilities and units, the EPG companies believe the costs estimated incorporated in this study for their units are representative for the purposes of this study.[6]

The range of costs observed for most of the units are shown below. However, a few units have reduction costs that are higher than the upper end of the range shown in the table below. These very high costs result from technologies applied to low-concentation emission streams or sources that have unique site circumstances.[7] The cost effectiveness values are the sum of the annualized capital costs (annualized at 10% over 20 years) plus annual operating and maintenance costs, divided by the tonnes of emissions reduced.

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[6] Cost differences were also point out to Alberta Environment. Alberta Environment's general direction has been to incorporate the costs as provided by EPG sector representatives.

Table 9: Typical Range of Costs for SOx Emission Reduction Technologies

(Costs at some units are outside the ranges shown due to unique site-specific conditions)

Primary SOx Technologies	% Reduction	Capital Cost	Operating & Maintenance	Cost Effectiveness
		($/kW)	($/MWh)	($/tonne-reduced)
Lime Spray Drying	90%	200 to 400	2 to 3	1,000 to 4,000
Limestone Scrubbing (Forced Oxidation)	95%	200 to 400	2 to 3	1,000 to 5,000
Limestone Injection in Furnace With Activation Chamber	63%	120 to 260	1.2	2,000 to 3,000
Lime Injection Multi-stage Burners	55%	115 to 170	2.5 to 3.0	2,000 to 5,000
Fuel switching to gas (based on gas price of 4 $/GJ)	100% (or portion thereof)	30 to 45	30 to 40	6,000 to 10,000

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[7] The few extremely high costs were provided as input to MARKAL but excluded from the ranges shown here, since it could leave the impression that these cost results are typically representative of a significant portion of the cost estimates for the technologies shown.

Table 10: Typical Range of Costs for NOx Emission Reduction Technologies

(Costs at some units are outside the ranges shown due to unique site-specific conditions)

NOx Technologies	% Reduction	Capital Cost	Operating & Maintenance	Cost Effectiveness
		($/kW)	($/MWh)	($/tonne-NOx-reduced)
Low Reduction Options • Improved instrumentation • Operator care • Low excess air • Over-fired air • Low NOx Concentric Firing Systems	5 to 25%	3 to 10	0.01 to 0.03	150 to 700
Low NOx burners	20 to 80%	30 to 40	0.1 to 0.3	950 to 2,000
Selective Non-Catalytic Reduction Technologies	45%	16 to 35	0.4 to 0.6	750 to 2,000
Natural gas reburn (related to 15% gas substitution)	60%	15 to 30	4 to 5	3,500 to 5,000
Selective catalytic reduction	70 to 85%	120 to 200	1.2 to 1.6	1,900 to 2,500

3.5.1 Costs of GHG Emissions Reductions

The technologies to reduce GHG emissions for EPG facilities have been estimated in the National Climate Change Process (NCCP). The Electricity Table and the Analysis and Modelling Group (AMG) of the NCCP analyzed GHG emission reduction options and costs for the sector. These costs are reflected in the MARKAL model, which had been applied in support of the NCCP and the Electricity Table. This study did not repeat previous work in this field and, instead, utilizes the costs for GHG emission reductions previously developed under the NCCP and through MARKAL. Literature on this work is available at the NCCP website (www.nccp.ca).

Several reference estimates of capital and operating costs for GHG emissions reduction identified in the field research are provided below. The costs of some of the technologies that can achieve medium levels of GHG emission reduction are very strongly dependant on the price of natural gas, which is determined endogenously in MARKAL.

Table 11: Range of Typical Costs for GHG Emission Reduction Technologies

(Costs at some units are outside the ranges shown due to unique site-specific conditions)

NOx Technologies	% Reduction	Capital Cost	Operating & Maintenance
		($/kW)	($/MWh)
Natural gas substitution for coal (simple cycle)	~45 to 50%	30 to 45	30 to 40
Natural gas combined cycle	~66%	600 to 800	Developed in MARKAL
Integrated gas combined cycle	~20%	~1200	Developed in MARKAL
Amine scrubbing* (and storage or use) Excludes (storage costs)	>95%	1040 +	29
Pure oxygen combustion* (and storage or use) Excludes (storage costs or use values)	>95%	1024 +	17

* Source: Alberta EPG company (not named for reasons of confidentiality). Note: Costs shown above may change based on MARKAL modelled results.

3.6 Measurement and Monitoring

EPG facilities conduct periodic stack testing to measure emissions for reporting to Alberta Environment or other government departments. Periodic measurements may not always be representative of maximum or average annual conditions. Emissions can fluctuate depending on fuel quality, fuel content and various operating parameters. Facilities can also estimate emissions based on the content of fuels and mass balance techniques (e.g. SOx emissions from sulphur content of coal and ash). Standard emission factors can also be applied (e.g. US EPA AP-42 factors). All coal-fired facilities in the EPG sector employ continuous emissions monitoring for SO_x and all but one facility has continuous monitoring of NOx emissions. Continuous emissions monitoring (CEM) systems could be applied to measure annual emission quantities more accurately than would be determined by periodic testing.

4. Chemicals

4.1 Industry Overview

The chemicals sector (standard industry classification SIC-37, NAICS-325) includes a variety of organic and inorganic chemical producers and formulators. The chemicals sector in Alberta may include upwards of 100 to 150 companies, although 10 major petrochemical/polymer and fertilizer producers account for more than 70% of energy consumption and most of the chemical sector CAC emissions in the province.

Table 12: Major Chemical Facilities Covered in this Analysis

(Estimated Capacities)

Company / Facility Name	Location	Census Region	Primary Products	Capacity (kilotonnes/yr)
Ethylene, co-products and derivatives				
Novacor Chemicals	Joffre	8	Ethylene and co-products	2,800 Ethylene
Dow Chemical	Fort Saskatchewan	11	Ethylene and co-products	1,200 Ethylene
AT Plastics Inc	Edmonton	11	Polyethylene	150
Shell Scotford Styrene	Scotford	11	Styrene	370
Shell Scotford Styrene	Scotford	11	Ethylene Glycol	430
Fertilizers				
Agrium	Carseland	5	Ammonia	500
Agrium	Fort Saskatchewan	11	Ammonia	460
Agrium	Redwater	11	Ammonia Sulphuric Acid	760 Ammonia
Canadian Fertilizers	Medicine Hat	1	Ammonia	1,000
Canadian Fertilizers	Medicine Hat	1	Urea	760
Orica	Carseland	5	Ammonium Nitrate Nitric Acid	284
Sherritt International Corporation	Fort Saskatchewan	11	Ammonia Sulphuric acid	356 Ammonia
Other				
Cancarb	Medicine Hat	1	Carbon Black	50
Marsulex	Fort Saskatchewan	11	Hydrogen Sulfides and Carbon Disulfides	7

Alberta's chemical sector can be divided into 3 main groups, namely: the fertilizer plants, the petrochemical plants; and the remaining smaller miscellaneous plants. Products from the chemical sector are numerous. Usually, multiple products are produced from each plant. The main products from the petrochemical plants are ethylene, its co-products (propylene, benzene, butylenes, etc.) and its derivatives (polyethylene, ethylene glycol, styrene, etc.). Ammonia is a major product of the fertilizer plants. The fertilizer plants can also make urea (from ammonia and carbon dioxide), as well as combine ammonia with inorganic chemicals to make inorganic fertilizers. The remaining chemical plants analyzed in this study produce a variety of products including carbon, carbon black, hydrogen sulphides and carbon disulphides.

The fertilizer facilities covered for this project accounted for 100% of the ammonia and ethylene production in Alberta. These facilities also account for the majority of energy consumption in the sector.

4.2 Processes and Energy Use

There are many chemical processes employed within Alberta. The sections that follow provide brief simplified descriptions of the main processes in Alberta and the use of energy. The general information on energy provided should not be considered representative for any specific facility. Since there may be only be one or a few companies making some products, company specific proprietary information (that is not already in the public domain) is not included in these descriptions.

4.2.1 Ethylene

Ethylene plants are typically the core of a "petrochemicals" complex. Ethylene is used to make so-called derivative products such as: polyethylene, ethylene oxide and glycol, styrene and 1,2-dicholorethane (DCE) in Alberta. These are major export products for the province.

Most of the energy used in making ethylene, co-products and derivatives is consumed in the ethane feedstock cracking furnaces. There are dozens of such furnaces among Dow's and Nova's ethylene operations. These vary in size, age, efficiency, throughput capability, yield, and NOx emissions rates. Boilers and cogeneration units that are located on-site at Nova Joffre facility and Dow's Fort Saskatchewan facility are the other energy-using equipment (and other significant emission sources of NOx emissions). Furnaces, as well as other equipment use natural gas, as well as recycled gases containing significant portions of hydrogen. However, hydrogen can be a valuable chemical feedstock and therefore less of it may be used in the future. Only the furnace crackers, boilers and cogeneration units were addressed in this analysis.

4.2.2 Ammonia and Urea production

A fertilizer plant can consist of an ammonia plant by itself or an ammonia plant combined with a urea plant and/or inorganic ammonia based fertilizer plant. Ammonia is produced by reacting nitrogen and hydrogen in the presence of a catalyst at high temperature. Ammonia plants typically rely on reforming methane contained in natural gas for their hydrogen needs. Steam methane reforming (SMR) plants can make hydrogen in sufficient quantities to support large-scale ammonia production. Carbon dioxide or pressure swing absorption air separation plants are typically employed to obtain the nitrogen. Oxygen is a co-product of air separation. Ammonia is a basic fertilizer product that can be sold as anhydrous or combined with inorganic acids (nitric, sulphuric or phosphoric) to make inorganic fertilizers.

Methane Reforming for Hydrogen Production

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$$
$$N_2 + 3H_2 \rightarrow 2NH_3$$

Urea is made by reacting ammonia with carbon dioxide. Approximately 0.6 kg of ammonia and 0.75 kg of carbon dioxide are required for every 1 kg of urea produced. Typically, urea production is integrated to ammonia plants that also produce spare carbon dioxide. Production involves the following chemical reaction.

$$2NH_3 + CO_2 \rightarrow NH_2CONH_2 + H_2O$$

Total (including fuel and feedstock) natural gas requirements for ammonia production are typically between 28 and 45 GJ/tonne of ammonia produced, depending on the age and efficiency of the plant. New facilities are more efficient than older units. In the production of fertilizers, large amounts of energy are required to reform the natural gas into hydrogen and carbon monoxide (and dioxide), as well as to separate products. Typically 35 to 40% of the gas consumption for fertilizer plants is needed for fuel and the rest is feedstock. Most of the energy use is in the reformers. There can also be compressors, boilers and other energy-consuming equipment.

4.2.3 Carbon Black

In Alberta, Cancarb uses natural gas as a feedstock in the production of specialty grades of carbon black. Most other North American carbon black plants make other grades of "black", using petroleum liquid feedstocks. To make carbon black, the feedstock is fed into furnace, where it is heated to a high temperature, thereby breaking the hydrogen-carbon bonds to yield the desired carbon product. The gas stream containing the carbon powder is filtered and the carbon black is extracted from the gases. Energy is required to keep the reaction going.

4.2.4 Nitric Acid and Sulphuric Acid

There are plants in Alberta making nitric and sulphuric acid. The production process for these two acids is similar. In the case of nitric acid, production involves the oxidation of ammonia (with oxygen from the air) at a very high temperature to produce oxides of nitrogen. The NOx is then passed through an absorber. NO_2 is absorbed with water to produce nitric acid. The reaction is exothermic, and energy requirements are low.

Sulphur acid is produced by the oxidation of elemental sulphur to make sulphur oxide. Water is added and the resulting acid is absorbed (with sulphuric acid). Sulphur that can is not recovered in the absorption stages results in emissions (unless controlled).

4.3 Emission Sources

The main sources of NOx emissions in the chemical sector are from combustion of fossil fuels in reformers at ammonia plants, furnaces at ethylene plants, compressors, boilers and cogeneration units. Sulphuric acid plants are largely responsible for the SOx emissions in Alberta's chemical sector. No use of sulphur-containing fuels (coal and heavy fuel oil) was identified among the chemical facilities analyzed in this study.

The chemical industry in Alberta is large and quite complex, with many small sources of NOx and SOx emissions. Approximately 75% of the total NOx emitted from the chemical sector has been accounted for in this project and for which emission reduction costs have been prepared. Approximately 80% of the total SOx emissions from the chemical sector have also been accounted for. A low volume of SOx is emitted by this sector and, for that reason, these emissions were not targeted for this analysis. Moreover, the SOx emissions are from processes at sulphur acid production facilities not connected to NOx and GHG emissions. These SOx emissions form part of the uncovered sources.

Table 13: Coverage of Emissions from Chemicals Sector, 2000

(kilotonnes)

Contaminant	**NO$_x$**	
Emissions from facilities surveyed	19.3	80%
Emissions accounted for in costing analysis	16	75%
All other facilities and area sources *	4-5	25%
Total estimated emissions #	24	100%

* Other facilities and area sources have not been included in the study. # Total excludes Alcan, which is included in Petroleum Refining sector - SIC 29. Alcan classifies itself under NAICS 324 (SIC 29) (Personal Cheminfo Services interview, Dec. 2002). Emission inventory and forecast estimates have previously included Alcan as part of chemicals sector.

4.3.1 Ethylene Facilities

Ethylene plants (including on-site cogeneration units) account for nearly 30% of Alberta's total chemical sector NOx emissions. At ethylene plants approximately 70 to 90% of the total NOx emissions are from the feedstock cracking furnaces. Boilers and cogeneration units account for the rest. Insignificant amounts of SOx emissions were identified from the ethylene producers.

1.3.2 Ammonia/Urea Facilities

NOx emissions from ammonia plants account for approximately 30 to 40% of the total NOx emissions in the chemical sector in Alberta. The major sources of NOx emissions are the reformers. NOx emissions from the reformers can account for 90% of the total NOx from a fertilizer plant. The emission contribution from the reformer furnaces can be lower if the energy demand at the facility requires boilers to make steam and/or has cogeneration units (making electricity and steam). For a facility that does have boilers, NOx emission from the reformer may account for only approximately 75% of the total NOx. The major source of NOx emission at urea plants is usually related to the generation of steam from boilers. NOx emissions from integrated ammonia/urea facilities can account from 5 to 20% of the total NOx emissions of the complex.

The sulphuric acid facilities in Alberta account for the majority of the SOx emissions from the chemical sector. (Alcan's facility which makes carbon for anodes has been previously included in the chemical sector. However, Alcan defines itself as part of the Petroleum Refining sector under SIC 29, NAICS 324. Refer to Petroleum Refining Sector analysis of this Appendix).

1.3.3 Nitric Acid Facility

Nitric acid production results in NOx process emissions (as opposed to combustion related emissions). The excess product NOx that is not absorbed in the process (i.e., not made into nitric acid) is released.

4.4 Reduction Technologies

In the interviews, it was found that only a few companies in the chemical sector had identified specific technologies that could address their NOx emissions. The major reasons for this is that companies are in compliance with approved emission levels and were not anticipating any new requirement to address their emissions. However, a few companies had conducted technical and economic evaluation of the various NOx emission reduction technology options. Most of the NOx reduction technologies are similar to those identified by other sectors (e.g. SCR, SNCR, scrubbers for SOx, etc.). Only a few unique technologies were identified by specific companies.

Table 14: Identified Technologies Selected for Costing Purposes

NOx Technologies	% Reduction	Ethylene	Ammonia	All Other
Low excess air	15%	X	X	X
Low NOx burners	41%	X	X	X
Selective non-catalytic reduction technologies	45%	X	X	X
Selective catalytic reduction	85%	X	X	X
Catalytic Converter for Internal Combustion Gas Compressors	75%		X	
Steam injection in cogeneration units	~60%	X		

A few units at facilities in Alberta's Chemical's sector have already employed low-NOx burners or similar technologies that minimize NOx emissions. For example, modern ethylene furnaces have burner configurations that can achieve 20% to 40% lower emissions than older furnaces per unit of production.

Some facilities have reported that increasing operator care, making operational changes such as monitoring and controlling flue gas and installing online analyser to continually adjust performance in terms of NOx emissions would also provide a reduction in NOx emissions. Other facilities reported that integration of new technologies into the outmoded technologies that are currently operated at the facilities would not be possible.

4.5 Costs of Reduction Technologies

There is a wide range of estimated capital, operating and maintenance costs for addressing emissions among facilities and units in the chemicals sector. Some of the major factors resulting in the wide range of estimates include differences in:

- size of facilities and related economies of scale for capital installations;
- rates of emissions;
- efficiency of units (i.e., heat rates);
- stack gas flow rates for each unit per unit of electricity generated;
- stack gas temperatures;
- space limitations at some facilities;
- ratio of capacity to actual average generation rates; and
- different reduction effectiveness estimated by companies for similar technologies.

In some cases, chemical units and related emissions are operating at low rates of capacity utilization, such that their emissions are low. However, this results in high capital costs per unit of emissions-reduced.. Most of the costs for the facilities are in the low end of the range shown in the tables below.

Table 15: Typical Range of Cost for NOx Emission Reduction Technologies for Reformers in the Chemical Sector

($/tonne NOx reduced)

	% Reduction	Annualized Total	Capital	Operating & Maintenance
Low Reduction Options*	15% - 25%	$390 - $3,150	$2,900 - $23,400	$50 - $405
Low NOx burners	41%	$980 - $7,330	$7,290 - $54,350	$127 - $945
Selective Non-Catalytic Reduction Technologies	45%	$1,160 - $7,275	$5,425 - $50,650	$480 - $1,325
Selective catalytic reduction	85%	$4,890 - $16,565	$7,745 - $54,315	$3,960 - $10,185

* Improved instrumentation, operator care, low excess air

Table 16: Typical Range of Cost for NOx Emission Reduction Technologies for Furnaces in the Chemical Sector

($/tonne NOx reduced)

	% Reduction	Annualized Total	Capital	Operating & Maintenance
Low Reduction Options*	15% - 25%	$960 - $2,040	$7,135 - $15,163	$123 - $263
Low NOx burners	41%	$2,445 - $13,235	$18,130 - $108,635	$316 - $559
Selective Non-Catalytic Reduction Technologies	45%	$2,430 - $9,000	$14,000 - $56,972	$784 - $2,845
Selective catalytic reduction	85%	$6,610 - $16,410	$19,000 - $69,300	$2,270 - $10,680

* Improved instrumentation, operator care, low excess air

Table 17: Typical Range of Cost for NOx Emission Reduction Technologies for Boilers in the Chemical Sector

($/tonne NOx reduced)

	% Reduction	Annualized Total	Capital	Operating & Maintenance
Low Reduction Options*	15% - 25%	$655 - $2,100	$4,870 - $15,600	$85 - $270
Low NOx burners	41%	$1,620 - $5,220	$12,025 - $38,700	$210 - $675
Selective Non-Catalytic Reduction Technologies	45%	$1,765 - $4,745	$9,900 - $31,575	$605 - $1,035
Selective catalytic reduction	85%	$5,335 - $10,380	$12,655 - $40,215	$3,845 - $5,655

* Improved instrumentation, operator care, low excess air

4.6 Measurement and Monitoring

Chemical facilities conduct periodic stack testing to measure emissions for reporting to Alberta Environment or other government agencies. Periodic measurements may not always be representative of maximum or average annual conditions. Emissions can fluctuate depending on fuel quality, fuel content and operating parameters (temperatures, etc.). Facilities can also estimate emissions based on the content of fuels and mass balance techniques. Standard emission factors are often applied (e.g. US EPA AP-42 emission factors). Some facilities in the chemicals sector employ continuous emissions monitoring for NOx. Continuous emissions monitoring (CEM) systems could be more broadly applied to measure annual emission quantities more accurately than would be determined by periodic stack testing.

5. Lumber and Allied Wood Products

5.1 Industry Overview

The Lumber and Allied Wood Products sector (SIC 2522, 2591, 2592, 2593 and NAICS 321) in Alberta is comprised of approximately 52 facilities that manufacture dimensional lumber in lumber or "saw" mills and reconstituted wood panel products in panel board mills. There are approximately 44 lumber mills and 8 panel board mills operating in Alberta, capable of producing a total of approximately 10 million cubic meters of wood products per year. Total wood product sales are estimated at $3 billion annually, making this the fourth largest manufacturing sector in the province.

Table 18: Summary of Alberta Lumber and Panel board Mills

(Top 8 Lumber Mills and All Panel board Mills)

Company	**Location**	**Capacity**	**Capacity**
Lumber Mills		(mmfbm/y)	(000's m^3/y)
Tolko Industries Ltd.	High Level	251	592
Hi-Atha Sawmill	Hinton	250	590
Blue Ridge Lumber (1981) Ltd.	Blue Ridge	250	590
Paul's Sawmill & Planer	Peace River	250	590
Natal Forest Products Ltd.	Coleman	250	590
Weyerhaeuser Company Ltd.	Grande Prairie	210	495
Millar Western Forest Products Ltd.	Whitecourt	208	491
Sunpine Forest Products Ltd.	Sundre	190	448
36 Smaller Lumber Mills		1,424	3,360
Total Lumber Capacity (44 Mills)		**3,283**	**7,744**
Panel board Mills		**(mmft^3/y - $^3/_8$")**	**(000's m^3/y)**
Ainsworth Lumber Co. (OSB)	Grand Prairie	615	544
Tolko Industries (OSB)	High Prairie	525	465
Weyerhaeuser Ltd. (OSB)	Edson	410	363
Weyerhaeuser Ltd. (OSB)	Drayton Valley	365	323
Weyerhaeuser Ltd. (OSB)	Slave Lake	250	221
Alberta Plywood Ltd (Softwood Plywood)	Edmonton	240	212
Rangerboard (MDF)	Whitecourt	240*	212
Total Panel board Capacity		—	**2,341**
Alberta Plywood Ltd (Softwood Veneer)	Slave Lake	237 mmfbm/y	559

Source: Madison's Canadian Lumber Directory, company interviews

Note: mmfbm/y - millions of foot-board measures per year

* Rangerboard's MDF output is expressed as 120 mmfbm/y on a ¾" basis (equivalent to 240 @ $^3/_8$").

The current Alberta lumber production capacity from the 44 mills is 7.7 million m^3 per year (3,283 mmfbm/y).[8] The sector produced 6.3 million m^3 of lumber in 2000.[9] The production capacities of Alberta lumber mills range from less than 5 mmfbm/y up to about 250 mmfbm/y and the 15 largest mills account for over 80% of sector output. Although some large lumber mills are integrated with pulp & paper or panel board operations, most Alberta lumber mills are independent operations. Shakes and shingles (SIC 2521) are usually considered part of the wood products sector, but there are no known operations in Alberta.

The 8 panel board mills in Alberta can be categorized into four different types: 5 oriented strandboard (OSB) mills; 1 medium-density fibreboard (MDF) mill, 1 softwood plywood (S-PLY) mill and 1 softwood veneer mill. The latter mill provides 1/8" sheets of veneer material for softwood plywood mills that do not have internal veneer peeling operations. There are no particleboard mills in Alberta. The output for OSB and S-PLY mills is measured in millions of square feet on a 3/8" thickness basis, while MDF uses a ¾" basis. The capacity range for panel board mills does not vary as widely as lumber mills; all mills fall into the 240-615 million square feet (3/8") range.

According to industry sources, overall production is not expected to grow significantly over the next ten years (i.e., 1 % annual growth for lumber mills, 1.5% annual growth for panel board mills) because harvest levels of raw timber are already at their sustainable limits.

5.2 Processes and Energy Use

5.2.1 Lumber Mills

The basic processes in lumber mills are usually the same, regardless of the size. A typical fully-integrated lumber mill normally consists of the following sections:

1. A primary breakdown section, where logs are debarked;
2. A secondary breakdown section, where most dimensional lumber is cut;
3. Drying kilns, which are heated either by natural gas burners or thermal oil loops, where the moisture content of green lumber is reduced to about 5-15%;
4. A planer mill, where the surfaces of rough dry lumber are finished in a multiple-knife planer to the final product size; and
5. A wood waste incinerator, and/or some other residual management system, which processes all the waste wood from the manufacturing process into appropriate products, including wood chips, hog fuel, sawdust and shavings.

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[8] *Madison's Canadian Lumber Directory*, 45th Edition, July 2002. Lumber mills measure output volume in millions foot-board measures per year (mmfbm/y). One million board feet are equivalent to 2,358 m^3.
[9] Statistics Canada, 33-001, Dec. 2000.

5.2.2 Panel Board Mills

Each type of panel board (OSB. MDF, S-PLY) is produced using a unique process. However, a few process elements are common to most panel board mills. These include:

- Cutting and preparing the raw wood material;
- Drying of raw material;
- Application of resin binder (and adjuncts) to the wood raw material;
- Hot pressing the panels
- Cutting, finishing and cooling;
- Energy generation for dryers and presses

A brief description of the unique production processes for each product category is provided below. Information was summarized from mill interviews and supplemented by technical information provided by some companies.

5.3 Energy Use

The production of wood products requires both electrical energy (for material handling, cutting, air compression, and refining) and thermal energy (principally for drying operations). In all wood product mills, the amount of thermal energy (from natural gas or wood waste combustion) required is at least 3 times the amount of electrical energy required, as shown in the table below. Coal and liquid fuel oils are not used, except for some minor diesel use in stationary generators.

Table 19: Specific Energy Use by Mill Type

(Canadian Mill Averages - TJ/ M m^3)

	Lumber	%	OSB	%	MDF	%	Softwood Plywood	%
Electricity	207	18	599	12	2,354	23	509	11
Thermal	957	82	4,332	88	8,031	77	3,987	89
Total	**1164**	**100**	**4931**	**100**	**10,385**	**100**	**4,496**	**100**

Source: Cheminfo Services[10]

5.3.1 Lumber Mills

Most of the electricity used in a sawmill is for the primary and secondary breakdown operations, where logs are debarked and cut into boards. Various electric motors account for over two-thirds of a mill's electricity bill. Planing, residual wood processing and handling account for most of the remainder.

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[10] Cheminfo Services Inc., *Wood Products Industry Energy Use & GHG Emission Reduction Opportunities*, Mar. 1999, (GHG Foundation Paper for Forestry Table)

Table 20: Lumber Mill Energy Use by Process

(Averages from Sample of 50 Canadian mills - % of Total Mill Energy Use)

Process	Electricity	Thermal
Feed Preparation	60%	
Drying	10%	90%
Conversion		
Finishing/Other	30%	10%
Total	100%	100%

Source: Cheminfo Services[11]

The fuels used for thermal energy in lumber mills are natural gas and various forms of wood waste (e.g. chips, sawdust, planer dust, bark). Most of the larger Alberta mills have used natural gas along with some wood waste, but with the current (2002) high natural gas prices, facilities are beginning to shift to more wood waste combustion.

Drying constitutes the major thermal energy requirement at the lumber mills. Some mills report as much as 90% of thermal energy is used for drying. A large lumber mill may use several kilns totalling as much as 100-150 mmbtu/hr. The other main thermal energy demands are the log pond and space heating. The proportion of energy used for drying at each mill varies depending on many factors, including: type of mill, portion of cut wood dried, wood species, kiln efficiency, and target moisture content of final products. Some mills, such as rough lumber, or planing mills may not dry their wood at all, and not all cut wood may be dried on-site.

5.3.2 Panel Board Mills

Panel board mills (softwood plywood, oriented strandboard, particleboard and fibreboard) are much more energy intensive than sawmills in both electricity and thermal demands. The largest electrical demands come from the saws, waferizers, and chippers, depending on the type of panel board mill. Medium density fibreboard mills have the highest electricity consumption of all the panel board mills, due to the high demand for mechanical energy in the fibre-refining process. Dryers account for the largest thermal energy demands in all panel board mills, while the rest is used to heat the presses, and for space heating.

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[11] Cheminfo Services Inc., *Wood Products Industry Energy Use & GHG Emission Reduction Opportunities*, Mar. 1999, (GHG Foundation Paper for Forestry Table)

Table 21: Panel board Mill Energy Use by Process

(Canadian Mill Averages - % of Total Mill Energy Use)

	OSB		MDF		Softwood Plywood	
Process	**Electricity**	**Thermal**	**Electricity**	**Thermal**	**Electricity**	**Thermal**
Feed Preparation	65%	10%	45%	40%	35%	5%
Drying	10%	60%	10%	40%	40%	55%
Conversion	10%	20%	20%	10%	10%	25%
Finishing/Other	15%	10%	25%	10%	15%	15%
Total	100%	100%	100%	100%	100%	100%

Source: Cheminfo Services[12]

MDF mills are the most energy intensive of all the panel board mills, both in terms of electricity use and thermal requirements. Major energy consuming operations for making MDF are debarking, fibre refining, drying and pressing. OSB mills and softwood plywood mills have similar levels of specific energy use.

More than 70% of total thermal energy for the panel board segment is supplied by waste wood or biomass combustion. Wood is usually burned in central boilers or furnaces with hot oil systems, although some dryers can be fired on sawdust. Natural gas accounts for the remaining fuel and is typically used in drying operations.

5.4 Emission Sources

The pollutants normally monitored in the wood products sector are particulate matter (PM), and volatile organic compounds (VOCs). This is especially true for facilities located near or in urban areas, where opacity levels are a public concern. This analysis focused on the emissions of gases most suited for trading in Alberta, namely SOx, NOx, and GHG. There are insignificant emissions of SOx from this sector, since wood and natural gas contain virtually no sulphur and very little fuel oil is used. Although CO_2 emissions are generated from wood waste combustion, the emissions are not counted in the national GHG inventory because they are assumed to be offset equally by the CO_2 taken up through plant photosynthesis. Emissions of other GHGs (e.g. CH_4, N_2O) are estimated to be less than 0.03 Mt CO_2e and CO_2 emissions from natural gas combustion are estimated to be less than 0.17 Mt CO_2e.[13] NOx emissions from the wood products sector are estimated at approximately 5.2 kt for the year 2000. The emission estimates are broken down into the following clusters.

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[12] Cheminfo Services Inc., *Wood Products Industry Energy Use & GHG Emission Reduction Opportunities*, Mar. 1999, (GHG Foundation Paper for Forestry Table)

[13] Cheminfo Services Inc., *Wood Products Industry Energy Use & GHG Emission Reduction Opportunities*, Mar. 1999, (Foundation Paper for Forestry Table).

Table 22: Estimated Wood Product Sector NOx Emissions, 2000

(kilotonnes)

Segment	Mill Count	Emissions
		(kt/y)
Large Lumber Mills with no Biomass Combustion	6	0.2
Large Lumber Mills with Biomass Combustion	6	1.7
Small Lumber Mills with Biomass Combustion	32	1.7
Panel board Mills	8	1.6
Total Wood Products	**52**	**5.2**

Source: Cheminfo Services estimates

The majority of NOx emissions come from the combustion of waste wood. A comparison of U.S. EPA emission factors for typical wood product mill combustion operations shows that NOx emissions from natural gas are lower relative to wood combustion.

Table 23: AP-42 Emission Factors for Wood Products Mills

(all converted to g/mmbtu)

Source	Fuel	Original Factor	Converted Factor (g/mmbtu)
Boilers/Furnaces	Natural Gas	100 lb/mmscf	45
Boilers/Furnaces	Dry Wood	0.49 lb/mmbtu	223
Boilers/Furnaces	Wet Wood	0.22 lb/mmbtu	100
Conical Burners	Wood (not specified)	1.0 lb/ton	59

Source: US EPA[14]

Lumber mills typically have only one or two significant sources of emissions--the boiler, or furnace unit, and the wood waste incinerator, if one exists. The drying kilns represent another possible source of direct emissions, depending on whether or not they are heated indirectly by thermal oil, or directly by natural gas-fired burners.

Because of their greater overall energy demands, panel board mills tend to have higher NOx emissions in relative terms compared to lumber mills. They also tend to have more direct sources of emissions. These sources include: the boiler, the dryers (which often have multiple stacks), and the press vent.

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[14] U.S. EPA, *AP-42 Fifth Edition, Volume I Stationary Sources*, 1995

5.5 Reduction Technologies

The table below summarizes the technologies that have been selected to estimate the costs to reduce NO$_x$ emissions from the lumber and panel board sector in Alberta. These technologies have either been identified by the facilities themselves or are identified within the literature to be among the most viable to achieve the range of emission reductions being modeled in this study. The effectiveness of these technologies can vary by unit and they may not be applicable in all situations.

Table 24: Selected Reduction Options for Wood Product Mills

Primary NOx Technologies	**Acronym**	**NOx Reduction**
Wood Waste Combustion		
Over-fire Air (or Air Staging)	OFA	25%
Low-NOx Burners	LNB	41%
Selective Non-Catalytic Reduction	SNCR	45%
Selective Catalytic Reduction	SCR	85%
Natural Gas-fired Kilns		
Low-NOx Burners	LNB	41%

Source: U.S. EPA Cost Models

5.5.1 Low NO$_x$ Burners

Low-NO$_x$ Burners (LNB) can be designed to handle certain types of dry, fine wood waste. The technique is similar to that of LNBs designed for firing powdered coal in electric power plants: turbulent mixing of air and fine solid fuel in sub-stoichiometric conditions, followed by successive introduction of remaining combustion air. There is no known use of LNBs in Alberta, since NOx permits in the sector do not control emissions. Conventional LNBs can be used in all natural gas combustion systems.

5.5.2 Over-fire Air (Air Staging)

Biomass has a much higher content of fuel-bound nitrogen compared to natural gas or fuel oil. Over-fire Air (OFA) technology has been identified as an effective method of reducing NOx emissions from wood waste combustion sources by 25%. Some recent industry studies have suggested that reduction efficiencies greater than 25% are possible.[15] The technique splits the stoichiometric combustion air so that the primary wood waste combustion zone is fuel-rich (oxygen lean), suppressing the tendency to oxidize nitrogen from the fuel. The balance of air is introduced in the secondary combustion zone above the burners. This is especially effective on wood waste from finishing operations (sawdust, sander dust and shavings) that have significantly higher nitrogen levels (up to 7%) due to the potential presence of nitrogen in urea formaldehyde (UF) and methylene diparaphenylene isocyanate (MDI) fast-drying resins. OFA techniques can be employed in wood waste boilers and incinerators.

Although somewhat similar in principle, Low Excess Air was not selected as a NOx control option because of its tendency to produce increased particulate and VOC emissions, which are strictly controlled at wood products mills.

5.5.3 Selective Catalytic Reduction

SCR systems (described elsewhere) offer a reliable and high-efficiency (85%) NOx control methods [words missing? – are not applicable?] to any flue gas stream in wood product plants. Stack temperatures must be at least 300°C for SCR systems to be effective. SCRs have high capital costs (partly due to the specialized catalyst required) and operating costs (because of ammonia or urea and catalyst replacement costs).

5.5.4 Selective Non-Catalytic Reduction

SNCR systems are effective in partially reducing NOx (45%) emissions from combustion gases, as long as the system can be installed in a hot (>800°C) exhaust gas zone of the combustion source. Capital costs are much lower than SCRs since no catalyst is used and operating costs are dominated by ammonia or urea reagent costs.

5.6 Costs of Reduction Technologies

The cost of reducing NOx emissions in Alberta's wood products mills vary widely for different sources. Some of the major factors resulting in the wide range of estimates include differences in:

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[15] Webster, T. & Drennan, S., Coen Company Inc., *Low-NOx Combustion of Biomass Fuels*,

- size of facilities and related economies of scale for capital installations;
- rates of emissions;
- efficiency of units (i.e., heat rates);
- stack gas flow rates per unit heat input
- stack gas temperatures;
- space limitations at some facilities;
- ratio of actual production level to capacity; and

For panel board mills, control option costs were developed directly for the major emission sources based on source parameters collected from industry interviews, available AENV background data and data from previous Cheminfo studies.

For lumber mills, control option costs were developed based on three model plants representing the averages of three distinct clusters of similar lumber mills: large mills without biomass combustion; large mills with biomass combustion; and small mills with biomass combustion. Sample data from 13 mills interviewed for this study, as well as available background data, were used. Capital costs for most options were based on the design heat rate of combustion sources. In some cases where direct parameter data was unavailable, reasonable estimates of heat rates and other parameters were made based on mill size.

The range of costs observed for the mills are shown below. Cost effectiveness is defined as the sum of the annualized capital costs (annualized at 10% over 20 years) plus annual operating and maintenance costs, divided by the tonnes of NOx emissions reduced.

Table 25: Cost Effectiveness for NOx Reduction Technologies

($/tonne NOx reduced)

NOx Technologies	**OFA**	**LNB**	**SNCR**	**SCR**
Reduction Efficiency	**25%**	**41%**	**45%**	**85%**
Large Lumber Mills (with no Biomass Combustion)	na	~$15,000	na	na
Large Lumber Mills (with Biomass Combustion)	$1,900	$3,500	$3,000	$4,500
Small Lumber Mills (with Biomass Combustion)	$3,700	$5,700	$6,400	$6,300
Panel board Mills (outlier costs excluded)	$700 - $1,500	$1,500 - $2,000	$1,500 - $2,500	$2,000 - $2,500

5.7 Measurement and Monitoring

Wood products mills conduct regular stack testing to measure PM and VOC emissions to demonstrate compliance with Alberta Environment operating permits. NOx emissions are not usually measured directly, but are often estimated for inventory purposes usually based on US EPA AP-42 emission factors. Since there are large differences between emission factors for natural gas and various wood combustion sources (wood NOx emissions can be up to ten times higher per unit energy), there is a great potential for emissions error through this method. Not all mills calculate or report NOx emissions for all sources. The 1995 and 2000 emissions data shows some major discrepancies between mills that appear to have similar operations. Continuous emissions monitoring (CEM) systems could be applied to emitting equipment to equipment to measure NOx.

6. Kraft Pulping

6.1 Industry Overview

There are 4 kraft pulp mills in Alberta (see Table 26), which contribute the majority of emissions from the pulp and paper sector in the Province. There are also 3 mechanical pulp mills in the Province: Slave Lake Pulp Corp. (Slave Lake); Alberta Newsprint Company (Whitecourt); and Millar Western Pulp Ltd. (Whitecourt). Mechanical mills are much less emissions intensive than kraft mills for NO_x and SO_x. As a result, the emphasis of data collection and analysis conducted on the pulp and paper section has been focused on the kraft mills in Alberta.

Nationally, Alberta has the 4th highest number of pulp lines (4 lines) in Canada, trailing, by a wide margin, British Columbia (16 lines), Quebec (10 lines) and Ontario (9 lines). Some kraft mills may have more than one production line. In total, Canada has 45 kraft production lines, distributed among 8 provinces. Overall, Canada is the second largest producer of pulp and the largest exporter of pulp in the world. Canada supplied 14% of the world's pulp demand in 1999.[16] Information on the location of the 4 kraft pulp mills in Alberta as well as their estimated annual pulp capacity is presented in Table below.

Table 26: Capacity of Kraft Pulp Mills in Alberta

Company	Region	Location	Capacity
			(kt/yr)
Alberta-Pacific Forest Industries Inc.	13	Boyle	612
Daishowa - Marubeni Int.	19	Peace River	460
Weldwood of Canada	14	Hinton	420
Weyerhaeuser Canada	19	Grand Prairie	280
Total Capacity			**1772**

Source: Cheminfo Services

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[16] AMEC Forest Industry Consulting, *Multi-Pollutant Emission Reduction Analysis Foundation (MERAF) for the Pulp And Paper Sector*, June 2002.

6.2 Processes and Energy Use

Wood is comprised of cellulose (fibres) and lignin (i.e. the substance that holds the fibres together). When the fibres are separated from the lignin, the result is wood pulp. The principle source of furnish used to manufacture pulp is wood from trees, while secondary fibers comprise the next most common furnish constituent (e.g. pre-consumer fibers such as mill waste fibers and post-consumer fibers (e.g. newsprint, corrugated boxes)). Other types of furnish include cotton rags and linters, flax, hemp, bagasse, tobacco, and synthetic fibers such as polypropylene.

Generally speaking, there are four types of pulp mills, categorized by the type of process utilized, namely: (i) kraft; (ii) sulphite; (iii) semi-chemical; and (iv) mechanical. Mechanical mills (such as chemi-thermomechanical, thermomechanical and stone groundwood) are electricity-intensive and therefore are generally less emissions-intensive than kraft mills. There are no sulphite or semi-chemical pulp mills in Alberta. This chapter therefore focuses exclusively on emissions from kraft pulp mills.

The basis of the chemical pulping process is the dissolving of the lignin bonds holding the cellulose fibres together. This process typically involves the cooking/digesting of wood chips in aqueous chemical solutions at elevated temperatures and pressures. There are three separate chemical processes that can be employed to produce pulp, namely: kraft, soda, and sulphite. These processes differ primarily in the specific chemicals that are used to facilitate the digestion process of the furnish. The only four chemical pulp mills in Alberta employ the kraft process in order to produce pulp.

For several reasons the kraft pulping is the most common production process employed in Canada (and Alberta).The chemicals used in the kraft process are selective in their attack on wood constituents, the pulp produced is stronger than those from other processes. In addition, the kraft process can be used with many different types of raw materials and can tolerate contaminants that are often found in wood (e.g. resins). Finally, the chemicals used in kraft pulping can be recovered quite easily, therefore saving significantly on chemical purchase costs as well as reducing environmental releases.

To digest wood in the kraft process, a sodium/sulphur-based alkaline pulping solution consisting of sodium sulphide and sodium hydroxide is used. This solution, referred to as white liquor, is mixed in a reactor vessel (digester) with the wood chips. The process results in the production of separated wood fibres (pulp) and a liquid containing dissolved lignin solids in a solution of pulping chemicals (black liquor). The black liquor is processed so that the original pulping chemicals are recovered and can be used again.

Following the kraft pulping process, spent cooking liquor is combined with pulp wash water to form a weak liquor. This weak liquor is concentrated to 65% solids, first through a multiple effect evaporator system and then a direct-contact evaporator (i.e. exposes the liquor to flue gases from the recovery boiler) or an indirect-contact concentrator. The concentrated liquor (i.e. strong black liquor) is then burned in a recovery boiler. Through the combustion of the organics in the black liquor, heat is generated which allows for the production of process steam used throughout the mill. The inorganic chemicals that were present in the black liquor are collected (as a smelt) in the bottom of the recovery furnace. This smelt is then dissolved in water, forming green liquor. The green liquor is then transferred to a causticising tank where quicklime is added to convert the solution back to white liquor. This white liquor is the solution used in the digester to separate the cellulose from the lignin.[17]

The majority of the energy consumed at kraft mills is derived from the biomass contained in the spent liquor. Wood wastes (i.e. hog fuel) are also used in steam boilers. This biomass is considered GHG neutral and is not accounted for as a source of CO_2 from the pulp and paper sector. Biomass is a source of NO_x, but not a significant source of SO_x. Natural gas is required for some boilers, dryers, lime kilns and other uses.

There has been an increase in the amount of energy utilization during the 1990's within the entire pulp and paper sector in Alberta (not just the kraft mills), as the capacity of the sector has increased. For instance, the energy derived from biomass and spent liquor has tripled over the 1990-2000 time-period. In addition, consumption of natural gas has more than tripled over this time-period.

Table 27: Trend in Energy Consumption Within Alberta's Pulp and Paper Sector

(Petajoules)

Energy Source	1990	1995	2000
Biomass and Spent Liquor	13.3	36.0	39.3
Natural Gas	3.3	7.3	11.7
Refined Petroleum Products	1.0	0.6	0.2
Electricity	5.5	10.6	13.2
Total	**2013.1**	**2049.5**	**2064.4**

Sources: Analysis and Modelling Group/Natural Resources Canada, *Canada's Energy Outlook: An Update* 1990 and 1995 data. Statistics Canada Report 57-003 for year 2000.

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[17] U.S. Environmental Protection Agency, *AP-42 – Chemical Wood Pulping*, January 1995.

6.3 Emission Sources

The main pollutants of concern from kraft pulp mills are nitrogen oxides (NO_x), particulates (PM), sulphur oxides (SO_x), volatile organic compounds (VOCs) and total reduced sulphur (TRS). While this analysis is focused on NO_x and SO_x emissions, a brief summary on the sources of the various pollutants of potential concern is provided below.

The primary sources of particulate emissions from kraft mills are the recovery boiler, lime kiln and smelt dissolving tank. For the most part, these emissions are sodium salts, with some calcium salts from the lime kiln. Other significant pollutants emitted from kraft mills are reduced sulphur compounds (e.g. hydrogen sulphide, methyl mercaptan, dimethyl sulphide, and dimethyl disulphide). The primary hydrogen sulphide emission source is the direct contact evaporator, where sodium sulphide in the black liquor reacts with carbon dioxide in the furnace exhaust. The lime kiln can also be a potential emission source, as a similar reaction occurs with residual sodium sulphide in the lime mud. Smaller amounts of hydrogen sulphide are emitted with the non-condensables in off-gases from the digesters and multiple-effects evaporators. Methyl mercaptan and dimethyl sulphide form during reactions with the lignin. The primary emission sources for these compounds are digester/blow tank systems and the direct contact evaporator.

Table 28: Average Contribution of NO_x and SO_x Emissions by Source at Kraft Pulp Mills

Source	NO_x	SO_x
Recovery boilers	40-60%	15-80%
Power boilers	40-60%	0-80%
Lime kilns	0-10%	0-35%

Source: Based on Cheminfo Services Inc. interviews.

Emissions of sulphur dioxide at pulp mills occur primarily from the oxidation of reduced sulphur compounds in the recovery boilers or power boilers. Nitrogen oxides are emitted from the recovery boilers, power boilers and lime kilns. Whereas the NO_x emissions are typically split between the recovery boilers and the power boilers, the source of the SO_x emissions can be much more variable, depending on whether the mill uses hog boilers to incinerate total reduced sulphur compounds. Reduced sulphur compounds can also be routed to the lime kiln for incineration. This will increase SOx emission from this source. Carbon monoxide is emitted from the recovery furnace and lime kilns, with the main emitting cause being the operation of the recovery furnace well above rated capacity, thereby making it impossible to maintain oxidizing conditions. The generation of auxiliary power (using coal, oil, natural gas, or bark/wood waste) and steam in the boiler is another major source of emissions from kraft mills.

6.4 Reduction Technologies

Provided below is a description of the technologies/practices that can be used to reduce SO_x and NO_x emissions from kraft mills. The focus of the discussion is on kraft mills, since these mills account for the majority of SO_x and NO_x emissions from Alberta's pulp and paper sector. Nevertheless, many of the technologies discussed below can also be applied to other types of mills.

6.4.1 Sulphur Dioxide

6.4.1.1 Installation of Scrubbers on the Recovery Boiler

Installing a flue gas scrubber can reduce SO2 emissions from the recovery boiler. A kraft recovery boiler scrubber of the wet type may include three process stages: a chloride zone; washing zone; and heat recovery zone. In the chloride zone, chloride is absorbed by cold water introduced in the flue gas inlet, while in the washing zone, SO_2 and particulates are removed. SO_2 reacts with the scrubbing liquor to form Na_2SO_3 and Na_2SO_4. H_2S can also be removed in the process, if the scrubbing liquor has a high pH value.

Scrubbers can be installed in conjunction with new boilers or retrofitted on existing boilers. The SO_2 removal efficiency is usually in the 90% range, which would achieve sulphur emission rates from an uncontrolled 0.5-2 kg SO_2/Adt down to 0.1-0.3 kg SO_2/Adt.

Note that SO_2 emissions from recovery boilers at Alberta kraft mills are generally low. While recovery boilers are suggested in the literature to be the primary source of SO_2 emissions from kraft mills, power boilers and the lime kiln appear to be significant contributors to SO_2 emissions at Alberta power plants. This is attributed to the unique operating characteristics of some of the Alberta kraft mills.

6.4.1.2 Increase the Dry Solids Content of Black Liquor

Black liquor is introduced into the recovery boiler in order to regenerate the white liquor that is used to separate the cellulose from lignin in the furnish. In the recovery boiler, the inorganic substances in the black liquor are reduced and separated as a smelt (mainly as Na_2S and Na_2CO_3) and the organic substances oxidized. Increasing the dry solids content of the black liquor prior to introduction into the recovery boiler can serve to reduce SO_2 emissions. Conventional evaporation will increase the dry solids content in the black liquor to 65%. The utilization of a superconcentrator can increase the dry solids content to 80%. As a result, SO_2 emissions are reduced to 0.1-0.3 kg/ADt of pulp or sometimes almost down to zero because more sodium will vaporise and react with sulphur. Particulate and NO_x emissions from the recovery boiler can however increase by using a superconcentrator. Superconcentrators can be applied at both new and existing kraft mills.

6.4.1.3 Collection and Incineration of Odorous Gases in the Lime Kiln

High and lean concentrated TRS gases can be collected with gas pipelines, ejectors and blowers for gas transfer. The collected lean malodorous gases can be incinerated as secondary air in the lime kiln, while the incineration of concentrated NCG can be carried out in the lime kiln. The concentrated NCGs contain over 90 % of all TRS-compounds generated in the cooking of pulp.

These collection and incineration systems can be employed at both new and existing kraft mills and can result in TRS emission reductions of over 90%. Added potential benefits are that sulphur in the gas can be absorbed in the lime, resulting in SO_2 emission reductions and 10-15% of the fuel used in the lime kiln can be replaced by the heat value of the concentrated malodorous gases (thereby reducing fossil fuel related emissions).

6.4.1.4 Collection and Incineration of Odorous Gases in a Separate Furnace Equipped with Scrubbers

Reduction in emissions of odorous gases can also be accomplished in a separate NCG incinerator that is equipped with a SO_2 scrubber. Both new and existing kraft mills can employ this option, which reduces TRS emissions over 90% by collecting and incinerating only the concentrated NCGs. SO2 emissions that are were previously released from the incineration of odorous gases without the presence of a scrubber, would be reduced by approximately 90%. A collateral impact of incinerating odorous gases in a separate furnace is that NO_x emissions are increased.

6.4.2 Nitrogen Oxides

6.4.2.1 Installation of Low NO_x Burners on Power Boilers

In low-NO_x burners, the primary burning air is brought through the burner in the fuel-air mix. Secondary and tertiary air is fed in separately in order to maintain an appropriate primary/secondary/tertiary air balance in the flame area. The purpose of the multi-phase air feed is to burn the fuel without excess air and as a result:

- there is not enough oxygen to promote strong NO_x formation; and
- the flame temperature is lower than in conventional burners which further decreases NO_x formation.

In addition, a portion of the NO_x formed will reduce back to elemental nitrogen when a residual amount of the fuel is burned in the outer flame area or outside it. Low NO_x burners can be used in both existing and new boilers. While conventional burners have a NO_x emissions rate of 250-500 mg/MJ, low NO_x burners achieve an emissions rate of 120-140 mg/MJ.

6.4.2.2 Use of Selective Non-Catalytic Reduction on Power Boilers

NO_x emissions from power boilers are typically small because of the low combustion temperature of the operation (i.e. NO_x emissions are usually in the range of 70-100 mg NO_x/MJ when only bark is fired, while emissions increase to 100-150 mg NO_x/MJ when oil is used). Selective non-catalytic reduction (SNCR) technology, which requires the injection of urea (or ammonia), can be employed in both existing and new power boilers, thereby reducing NO_x emissions by around 30-50%. This technology has been applied mostly to power boilers that are using biomass only or to boilers using a combination of biomass and fossil fuel.

6.4.2.3 Over Fire Air Technique on Recovery Boilers

Kraft recovery boilers operate with a reducing atmosphere; therefore, NO_x emissions are lower than in other types of furnaces. NO_x emissions can nevertheless be reduced from the recovery boiler through modifications to the air feed system. Thermal NO_x can be reduced through the fixation of nitrogen in the combustion gases by limiting the amount of air in the combustion zone. Systems have been designed specifically incorporating this fixation process by locating the air injection ports at the quartiary level. NO_x emissions can also be reduced by modifying the air feed system through introduction of a fourth air inlet in the upper part of the boiler. NO_x emission reductions associated with utilising the above techniques (i.e. the over-fire technique) are generally in the 20-40% range. Both new and existing kraft mills can employ these techniques. Emissions of CO and CO_2 can increase through the utilisation of this technique if not well controlled.

The over-fire technique can also be used on power boilers to reduce NO_x emissions. Its use in power boilers has been restricted to mills that use only biomass or a combination of wood and fossil fuel water wall boilers with small ports.

6.4.2.4 NO_x-OUT (SNCR)

A specific SNCR technology, referred to as the NO_xOUT process, is being developed to reduce NO_x emissions from recovery boilers in kraft mills. The recovery boiler is typically the largest emission source of NO_x at kraft pulp mills. Typical NO_x emission levels are between 50-80 mg/MJ. It is claimed that the NO_xOUT process can reduce NO_x emissions from an uncontrolled level of 80 mg/m^3 to approximately 55 mg/m^3 (i.e. a 30% reduction) and it has been suggested that up to a 50% reduction in NO_x emissions can be achieved with the technology. It should be noted that this technology is not currently at the commercialization stage and is therefore not considered further in this analysis.

6.5 Costs of Reduction Technologies

The estimated costs to install and operate various technologies (discussed in the previous section) to reduce emissions of NO_x and SO_x from kraft mills in Alberta are outlined in Table 29. A range has been provided for the costs of these technologies in order to reflect the uncertainty in the cost estimates as well as to take into account the scope of operations at the various kraft mills in Alberta. Technologies have been costed to reduce NO_x or SO_x emissions from the recovery and power boilers and the lime kiln.

The costs of the various emission control technologies were estimated for each mill in Alberta based upon several recent reports on the costs of NO_x and SO_x emission control among kraft mills. The costs outlined in these recent reports were prorated to Alberta kraft mills based upon the annual/daily capacity of the 4 kraft mills in Alberta and the capacity of the model mills used to estimate costs in the recent studies.

Table 29: Costs to Reduce Emissions of NO_x and SO_x from Alberta Kraft Mills

Pollutant	% Reduction	Technology Selection	Capital Costs	Operating and Maintenance Costs	Total Annualized Costs
			($/tonne of pollutant reduced)		
NO_x	25%	Low NOx Burner on Power Boilers	$11,100- $25,200	$1,800- $4,100	$3,100- $7,000
	40%	SNCR on Power Boiler	$9,000- $20,600	$2,300- $5,300	$3,400- $7,700
	35%	Overfire Air on Power Boiler	$3,000- $6,900	$900- $1,900	$1,200- $2,700
	35%	Overfire Air on Recovery Boiler	$25,000- $108,000	$2,300- $9,700	$5,200- $22,400
SO_x	90%	Scrubber on Recovery Boiler	$170,000- $600,000	$14,000- $55,000	$34,000- $125,000
	90%	Increase the Dry Solids Content of Black Liquor	$45,000- $225,000	-	$5,400- $26,000
	90%	Collection and Incineration of Odorous Gases in a Separate Furnace Equipped with Scrubbers	$7,000- $270,000	$300- $12,000	$1,000- $43,000

Note: capital costs were annualized at a 10% amortization rate and a 20 year amortization period.
Source: Cheminfo Services

6.6 Measurement and Monitoring

There are significant challenges with respect to the measurement and monitoring of NO_x and SO_x emissions from the pulp and paper sector. Currently, most kraft mills are using emission factors to estimate annual emissions from the various stacks at their facilities. Mass balance estimates for SO_x would probably be inappropriate, given the complex nature of the reactions involved in SOx production. More accurate estimates would require the installation of continuous emission monitors.

7. Cement

7.1 Industry Overview

There are two cement plants in Alberta: Inland Cement located in Edmonton; and Lafarge Canada with a plant in Exshaw. These two plants have a combined clinker capacity of approximately 2,200 kt/yr, which represents 14% of Canadian clinker capacity. Of the 16 currently operating cement plants in Canada, the Lafarge plant is the 3rd largest, while the Inland Cement facility is the 8th (in terms of clinker capacity).[18] Lafarge Canada operates two kilns at its Exshaw plant, one of which is a precalciner kiln, the most energy efficient clinker production technology. A second smaller long dry kiln is also in operation. Long dry kilns are less energy efficient than precalciner (or preheater) kilns. Inland Cement produces clinker at only one precalciner kiln in Edmonton. Both plants typically operate at close to capacity, with much of the cement production exported outside of the Province. The two plants are owned by multinational cement companies with headquarters located outside of Canada.

Table 30: Summary of Alberta Cement Plants

Facility	Location	Type of Kiln	Estimated Year 2000 Clinker Capacity (kt)
Inland Cement	Edmonton	Precalciner	930
Lafarge Canada	Exshaw	Precalciner	850
		Long dry	400
Total			**2,180**

Source: Portland Cement Association, *U.S. and Canadian Portland Cement Industry: Plant Information Summary*, 2001.

No new cement plants are expected to be built in Alberta in the foreseeable future. Although demand for cement will continue to increase in Alberta, new demand can be met with production from the existing plants. Each plant is projected to increase capacity in the future by debottlenecking.

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[18] Portland Cement Association, U.S. *and Canadian Portland Cement Industry: Plant Information Summary*, 2001.

7.2 Processes and Energy Use

Practically all fuel at cement plants is used in the kiln during pyroprocessing in order to produce clinker. The pyroprocess removes water from the raw meal, calcines the limestone at temperatures between 900-1,000°C and then clinkers the kiln material at about 1,500°C. Both cement plants have historically used natural gas as their primary fuel source, the only two cement plants in the U.S. or Canada to do so. However, both cement plants (i.e. all 3 kilns) have or are in the process of converting to the use of coal. High natural gas prices in the year 2000 and 2001 were one factor that contributed to the cement plants move to coal, as the primary fuel source. Inland Cement has indicated that their fuel conversion process will be complete in late 2002/early 2003 while Lafarge Canada has already completed the fuel substitution process.

In modern cement plants utilizing dry process technology, significant amounts of electricity are used to operate various fans and blowers associated with the preheater and precalciner equipment.[19] The finish grinding and follow-up processes are also large consumers of electricity at cement production facilities (i.e. approximately 40% of the plant's total electricity consumption).

7.3 Emission Sources

7.3.1 Primary Sources of Emissions

Emissions that are of primary concern from cement manufacturing facilities are oxides of nitrogen, sulphur oxides, particulate and carbon dioxide. Other pollutants emitted from cement facilities include volatile organic compounds, dioxins/furans and metals. The primary source of these emissions at cement manufacturing facilities is the kiln. Emissions result from physical and chemical reactions as well as the combustion of fuels. Practically 100% of the NO_x and SO_x emissions from cement facilities are from the kiln.

The two primary sources of NO_x emissions at cement production facilities (i.e. in the kiln) are thermal NO_x and fuel NO_x. Thermal NO_x forms at temperatures above 1,200°C and involves the reaction of nitrogen and oxygen molecules in the combustion air. Thermal NO_x is produced primarily in the kiln-burning zone where temperature levels are high enough to initiate this reaction. Fuel NO_x is produced by the combustion of the nitrogen that is present in the fuel. This nitrogen can either combine with other nitrogen atoms to form N_2 gas or react with oxygen to form fuel NO_x.

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[19] U.S. Geological Survey, *Cement.*

The primary source of SO_2 emissions from cement plants is the level of volatile sulphur compounds present in the raw materials fed into the kiln. For those kilns that are able to utilize low sulphur content raw materials, emissions of SO_2 are not a concern. However those kilns that rely on raw materials that contain organic sulphur or pyrite can have much higher SO_2 emissions. The sulphur present in fuels does not generally lead to SO_2 emissions from kilns that utilize preheater/precalciner systems. In these systems, SO_2 is captured in the clinker as a result of the strong alkaline nature in the sintering zone, the calcination zone and in the lower stage of the preheater. However there is not as much contact between the sulphur and alkaline material in long kilns and as a result, the sulphur present in the fuels can lead to higher SO_2 emissions.

Fossil fuel combustion (energy related emissions) and limestone calcination resulting in dissociation of CO_2 in the making of lime (non-energy related emissions) are the two important sources of CO_2 emissions in the cement production sector. In terms of non-energy emissions, CO_2 is generated when calcium carbonate ($CaCO_3$) from limestone, chalk, or other calcium-rich materials is heated in a high-temperature kiln, forming lime (CaO) and CO_2 in a process called calcination or calcining. CO_2 emissions from cement production are essentially directly proportional to lime content, so production of cements lower in lime yield less CO_2. The combustion of fossil fuels to generate heat in the kiln represent the majority of energy-related GHG emissions.

7.3.2 Trend in Emissions from the Alberta Cement Sector

Emissions of NO_x and SO_x from the Alberta cement industry are projected to decrease marginally in the future. The major factors contributing to changes in emissions include:[20]

- conversion to coal which lowers NO_x emissions (versus natural gas);
- installation of a new low-NO_x burners at one facility[21];
- controls applied to reduce SO_x by 25% from one facility by 2005 (lime injection is the option being considered by the facility); and
- continued improvements in energy efficiency.

Although cement facilities will use more coal in the future, which does contain sulphur, both producers indicate that there should not be additional SO_x emissions. The reason is that potential SO_x emissions are "scrubbed" by the process itself (i.e., in the kiln), such that the sulphur contained in the fuel is not emitted. The use of coal (vs. natural gas) will however increase CO_2 emissions from both Alberta cement plants vs. their year 2000 emissions.

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[20] Cheminfo Services, *Forecast of Common Air Contaminants in Alberta (1995 to 2020)*, April, 2002.

[21] Industry source. Highly uncertain NO_x reduction. No guaranteed reduction was provided by supplier.

7.4 Reduction Technologies

Outlined below are descriptions of those technologies that have been used to estimate the costs to reduce NO_x, SO_x and CO_2 emissions from the cement sector in Alberta. These technologies have either been identified by the facilities themselves or based on the literature are considered, to be among the most viable to achieve the range of emission reductions being analyzed in this study.

7.4.1 Nitrogen Oxides (NO_x)

7.4.1.1 Low NO_x Burners

Low-NO_x burners have been used within the cement industry for 20 years. These burners can be installed on any type of kiln, however additional modifications are required of direct-fired kilns (vs. indirect fired kilns). Specifically, a direct-fired fuel system must be converted to an indirect fired system, before low-NO_x burners can be installed. Different emission tests of low-NO_x burners report varying levels of emission reduction, for instance from 14% to 47%, depending on the type of kiln, fuel used and other facility specific parameters. Overall, reductions in NO_x emissions in the range of 25-30% are typically expected with low NO_x burners; however, in some instances no emission reductions have been achieved. Recent data indicate that 14% (22 kilns) of the operating kilns in the U.S. have installed a low-NO_x burner (81% of the facilities representing 81% of the operating U.S. kilns responded to the survey). The remaining 139 kilns that responded to the survey had not installed a low-NO_x burner.

7.4.1.2 Mid-kiln Firing (MKF)

Creating a reducing zone (i.e. a zone with lower temperatures) by firing lump fuel (i.e. solid and slow burning fuels) can result in NO_x emission reductions as a result of the fuel being burned at a lower temperature and by creating reducing conditions at the injection point, which may destroy some of the NO_x formed upstream in the kiln burning zone. This process is applicable to long wet and long dry kilns. Based upon experience to date, a maximum of about 15% of the total kiln fuel requirements can be injected at the mid-kiln location. Since long kilns typically do not generate temperatures in the range of 900-1,000°C, mid-kiln firing systems are being utilised in order to enable these kilns to use waste fuels that cannot pass the main burner (e.g. tires). The lump fuel (most often tires) is fed into the kiln with specially designed feed injection mechanisms. At least 21 long kilns in the U.S. and nearly 40 kilns worldwide have been modified to allow mid-kiln firing of solid and hazardous waste. The developer of MKF (i.e. Cadence) has stated that in emission tests conducted on seven dry kilns and three wet kilns, average NO_x emission reductions were 33% for dry kilns (ranging from 11% to 55%) and 40% for the wet kilns (ranging from 28-59%).

7.4.1.3 *Selective Non-catalytic Reduction (SNCR)*

SNCR systems can be applied in suspension preheater kilns and precalciner kilns. The desired temperature/retention time for SNCR is hard to achieve in long wet and dry process kilns, and therefore SNCR is not applicable to these types of kilns. The appropriate temperature window for SNCR is observed at several locations within preheater/precalciner type cement kilns, for instance in the cooler end of the rotating kiln, in the riser duct, and in the lower section of the cyclone preheater tower. Within preheater/precalciner kilns, ammonia water, containing 25% NH_3 is the most common reducing agent used in SNCR systems. There are at least 18 cement plants in Europe that are utilising SNCR systems (15 kilns in Germany, 2 in Sweden, and 1 in Switzerland). There is only 1 known application of SNCR (i.e. actually biosolids injection) in the U.S.

NO_x emission reductions achieved with SNCR technology vary based on several factors: the temperature, residence time, and ammonia and NO_x concentrations in the flue gas. If ammonia is injected at an NH_3:$3NO_x$ proportion of 1 to 1.5, NO_x emissions can be reduced by 60-80%. However, when a molar ratio of 0.5 is used, NO_x emission reductions of approximately 40% are achieved.

7.4.1.4 *Selective Catalytic Reduction (SCR)*

SCR systems have only been tested on preheater and semi-dry kilns; however, the technology may also be applicable to other kiln types. Pilot plant trials on small portions (three percent) of the exhaust gas have shown promise in various European countries. NO_x emission levels of approximately 100-200 mg NO_x/m^3 have been observed on pilot projects in Europe and there are current vendors in Europe offering SCR systems to the cement industry with these levels of performance. It has been reported that a full-scale SCR demonstration plant is being built at a cement plant in Germany (with government financial support) and another is supposedly under consideration in Austria. There are no known full-scale SCR installations at cement plants anywhere in the world.

7.4.2 Sulphur Dioxide (SO_2)

7.4.2.1 *Dry Reagent Injection*

Reagents (in wet or dry form) such as slaked lime, quicklime or activated fly ash with high CaO content can be added to the exhaust gas from the kiln in order to absorb some of the SO_2. The lime reacts with the SO_2 to form $CaSO_3$ and $CaSO_4$, which end up as part of the clinker composition. Kilns with moderate SO_2 concentrations in their exhaust can utilise this technique, which operates most efficiently at temperatures exceeding 600°C. Reductions in SO_2 emissions of 60-80% have been achieved when this technology is applied in suspension preheater kilns. The addition of reagent can be applied in all kiln systems; however, to date it has been applied most often in suspension preheaters.[22]

7.4.2.2 Wet Scrubber

Within the wet scrubber process, SO_x is absorbed (with calcium carbonate, hydroxide or oxide) by a liquid/slurry sprayed in a spray tower or bubbled through the liquid/slurry. The most common system utilised is the spray tower (i.e. all five wet scrubber systems operating at cement kilns in Europe utilise the spray tower). When utilising a spray tower, the slurry is sprayed counter-current to the exhaust gas and subsequently collected in a recycle tank at the bottom of the scrubber. The slurry cools the gases and reacts with SO_2 to form calcium sulphite and calcium sulphate. Air is then sprayed into the sump at the bottom of the tower to oxidise $CaSO_3$ to gypsum, which is of sufficient quality for use in the final Portland cement production step. It has been estimated that SO_2 emission reductions of over 90% can be achieved with this technology. All varieties of kilns can utilise a wet scrubber.

7.4.2.3 Dry Scrubber

Dry scrubbers are used to address very high levels of SO_2 emissions (i.e. greater than 1,500 mg/m^3). One specific variety of dry scrubber utilises a venturi reactor column to produce a fluidised bed of slaked lime and raw meal. As a result of contact between the exhaust gas and the absorbent, as well as the long residence time and low temperature characteristic of the system, SO_2 is very efficiently absorbed. Estimates suggest that SO_2 emission reductions of 90% can be achieved (corresponds to exhaust of 300 mg SO_2/m^3 when the initial SO_2 concentration is 3,000 mg/m^3). All varieties of dry kilns are potential candidates for a dry scrubber, although there is only one known installation of a dry scrubber at a cement plant (Holcim-Untervaz plant in Switzerland).[23]

7.4.3 Carbon Dioxide (CO_2)

7.4.3.1 Fly Ash

Fly ash is generated as a waste product by coal-fired electric generating plants. Fly ash can be added to cement at the finish grinding stage (blended cement) or it may be added as supplementary cementing materials to the concrete mix. In either application, production of cement clinker is reduced. The proportion of fly ash use in concrete varies from approximately 15% to 50% by weight of the final product. The major restriction on increased fly ash use in Alberta is the limit to which fly ash can be incorporated into various concrete applications. These limits vary among the different concrete products and in some instances are specified by either provincial or national specifications that must be followed. These limits are necessary as the incorporation of excessive amounts of fly ash can negatively impact certain properties of the concrete in its end-use application.

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[22] European Commission – Institute for Prospective Technological Studies, Integrated Pollution Prevention and Control (IPCC) - *Reference Document on Best Available Techniques in the Cement and Lime Manufacturing Industries*, March 2000.
[23] Ibid.

When fly ash is used in a blended cement to replace clinker or to replace cement in concrete, it reduces CO_2 emissions by roughly 0.85 tonnes for each tonne of cement that it replaces. Typically, fly ash specifications for blended cement/concrete manufacturers require a 2-4% LOI (loss on ignition) in order to be viable. The LOI refers to the percentage of the fly ash that is burnt on ignition and generally measures the carbon content, as this is the only material in the fly ash that will burn. Low carbon content in fly ash is necessary as carbon reacts unfavourably in cement and concrete and therefore affects its performance.

There is a large quantity of low-carbon content fly ash in Alberta that is currently available for use by cement producers/concrete facilities. A recent study (commissioned by Natural Resources Canada) has estimated that there is currently over 1 million tonnes of fly ash that is generated by coal-fired power plants in Alberta that is not being utilized (i.e. it is being disposed of). This fly ash has low carbon content, such that expensive upgrading of the fly ash is not necessary. Currently, only 100,000-150,000 tonnes of fly ash are being used by the cement/concrete sector in Alberta annually.[24]

7.4.3.2 Replace Coal with Natural Gas

Both Alberta cement plants have or are in the process of switching their primary fuel source from natural gas to coal. One of the results of this substitution is to increase CO_2 emissions. Both plants, once the switch has been made, will have the potential to use either coal or natural gas as fuel for the kiln. In order to reduce CO_2 emissions, the cement plants could use more natural gas and less coal (as compared to 100% coal).

7.4.3.3 Carbon Dioxide Capture and Disposal/Use

Cement plants could capture and subsequently dispose of or find uses for CO_2. There are several technologies either in the commercialization or the pilot stages that are able to separate and capture CO_2. Among the technologies that are available are carbon absorption, carbon adsorption, membrane systems and cryogenics. The use of monoethanolamine solvent in conjunction with carbon absorption is the most widespread of the current CO_2 capture technologies. CO_2 that is captured and not utilized to produce useful products must be stored. There are several CO_2 storage options that have been proposed and studied, for instance: (i) deep aquifers; (ii) depleted or uneconomic oil and gas reservoirs; (iii) deep ocean; (iv) salt domes and rock caverns; and (v) coal seams. Some of these storage options are being utilized in commercial applications today while others are in the pilot or R&D stage. CO_2 is currently utilized in several industrial applications. For example it is used in enhanced oil recovery operations, in the production of urea or methanol, and in refrigeration applications.

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[24] Interview with Natural Resources Canada, November, 2002.

7.5 Costs of Reduction Technologies

The estimated costs to install and operate various technologies (discussed in the previous section) to reduce emissions of NO_x and SO_x from cement plants in Alberta are outlined in Table 31. A range has been provided for the capital and annual operating costs of these technologies in order to reflect the uncertainty in the cost estimates as well as to take into account the scope of operations at the two production facilities in Alberta. Technologies have been selected and costs have been estimated for a low (i.e. 0-30%), medium (30-70%) and high (70-100%) emission reduction for the various pollutants of interest.

It should be noted that mid-kiln firing can only be used on long kilns (i.e. the long dry kiln operated by Lafarge in Exshaw) while selective non-catalytic reduction can only be used on short kilns (i.e. Lafarge's and Inland's precalciner kilns). Each of the other technologies identified in the Table below can be applied to the two types of kilns currently operating in Alberta (i.e. precalciner and long dry kilns).

The costs of the various emission control technologies were estimated for each kiln in Alberta based upon several recent government and industry reports on the costs of NO_x and SO_x emission control in the Portland cement sector. The costs outlined in these recent reports were prorated to Alberta cement kilns based upon the capacity of the 3 kilns and the capacity of the model kilns used to estimate costs in the recent studies. The capacity of the cement kilns is the most the significant determinant of emission reduction technology costs.

Table 31: Costs to Reduce Emissions of NO_x and SO_x from Alberta Cement Plants

Pollutant	% Reduction	Technology Selection	Capital Costs	Operating and Maintenance Costs	Cost Effectiveness
			($ per tonne of annual clinker capacity)		($ per tonne pollutant reduced)
NO_x	20%	Low NO_x Burners	$1-$3	<$1-$2	$950-$2,400
	35%	Mid-kiln Firing	$7-$9	$3-$4	$2,000-$3,000
	40%	Selective Non-catalytic Reduction	$2-$3	$2-$3	$4,500-$6,500
	85%	Selective Catalytic Reduction	$40-$75	$6-$8	$3,400-$11,200
SO_x	15%	Optimization of Clinker Burning Process	$0.5-$1	-	$100-$2,900
	40%	Absorbent addition (e.g. slaked lime)	$0.3-$1	$0.4-$0.8	$400-$7,900
	90%	Wet Scrubber	$8-$12	$0.5-$2	$1,000-$18,000

Note: capital costs were annualized at a 10% amortization rate and a 20 year amortization period.
Source: Cheminfo Services

With respect to reducing GHG emissions, the technologies that were identified by the Alberta cement plants were energy efficiency improvements and the use of fly ash to reduce clinker production. Inland Cement is also analyzing the feasibility of using landfill gas to replace some of its other energy purchases. Combustion of the landfill gas at the cement plant would reduce methane (which have a global warming potential of 21, versus 1 for the resultant CO_2) emissions from the landfill. This option has not been analyzed in this study as the boundary for analysis was within the border of the plants or immediately downstream of the plants (in the case of fly ash substitution at ready-mix concrete facilities).

Table 32: Costs to Achieve a 30% GHG Emission Reduction at an Alberta Cement Plant by Increasing Fly Ash Utilization in Alberta

Total Annual CO_2 Emissions to be Reduced (tonnes)	260,000
Quantity of Fly Ash Required (tonnes)	310,000
Cost Differential ($ per Tonne of Fly Ash - Cost to Produce a Tonne of Cement)	$30
Net Annual Operating Costs	$9,300,000
$ per Tonne of Annual Clinker Capacity	$10
Annualized Capital Costs*	$500,000
$ per Tonne of Annual Clinker Capacity	$4
Total Annualized Costs	$9,800,000
Cost Effectiveness ($/tonne of CO_2 reduced)	$37

* Capital costs are based on additional storage vessels required for the increased amount of fly ash being used by ready-mix facilities in the Province. These costs are calculated as 100 ready-mix facilities each requiring 2 additional fly ash storage vessels at a cost of $40,000 each. A portion of these costs has been attributed to the cement plant under analysis.
Note: capital costs were annualized at a 10% amortization rate and a 20-year amortization period.
Source: Cheminfo Services

The primary options to achieve somewhat significant GHG emission reductions at cement plants would be the following: (i) substitute natural gas for coal at the plants (note that both plants have or are currently in the process of converting to coal from natural gas, however each plant will have the capability to use either fuel in the future); (ii) substitution of fly ash for either clinker at the cement grinding facilities or for cement at ready-mix concrete facilities; and (iii) capture and either utilization or storage of CO_2. The fuel substitution and CO_2 capture options are to be addressed in subsequent analysis and reports to be undertaken/provided later in the study. In this analysis, the focus was on the substitution of fly ash.

7.6 Measurement and Monitoring

Currently both cement plants operate continuous emission monitors (CEM) to accurately measure their NO_x emissions. In addition, Lafarge Canada has recently installed a SO_2 CEM in order to ensure that they are in compliance with their new SO_2 annual emissions limit (another SO_2 CEM was already in place). Inland Cement indicated that they will start to monitor their SO_2 emissions when their fuel substitution process to coal is completed in the near future. Therefore, both facilities have (or will have in the near future) the capability to accurately measure current emissions of NO_x and SO_2 as well as to track emission reductions in the future. There are no CEMs for CO_2 emissions at either of the two facilities.

The cement sector in Alberta is highly concentrated with only two firms currently producing cement in the province. Measurement and monitoring issues are somewhat simplified because there are so few participants in the sector. In addition, practically all emissions of NO_x, SO_x and CO_2 originate from one process source, the kiln. Therefore emission monitors would only be required for one stack vs. multiple stacks in some other industrial sectors. It should be noted that Lafarge Canada operates two kilns at their Exshaw plant and would, therefore, have to install monitors on both of their kilns. As noted above, many of these CEMs are already in place.

8. Petroleum Refining

8.1 Industry Overview

Petroleum refining is categorized as part of SIC 29 (NAICS 324). There are five petroleum product refiners in Alberta, with the Parkland refinery, a smaller facility largely involved with processing condensates, currently idle. Also included in this sector is a division of Alcan Inc., which uses petroleum coke to make carbon. The carbon is subsequently used to make carbon anodes for use in aluminum production. Alcan categorizes itself as part of NAICS 324.[25]

Table 33: Petroleum Refining and Products Sector in Alberta

Company	Location	Crude Oil Processing Capacity
		(barrels/day)
Imperial Oil Ltd.	Strathcona	195,000
Petro-Canada Products	Edmonton Refinery	155,000
Shell Canada Products Ltd.	Scotford	100,000
Husky Oil Operations Ltd.	Lloydminster	24,000[a]
Parkland Refining Ltd.*	Bowden	(6,000 idle)
Alcan Inc. (Carbon product from petroleum coke)	Strathcona	#

* Currently idle. # Confidential. Source: Oil & Gas Journal, Dec. 21, 1998 (reported Jan. 1, 1999 capacities) a) Asphalt plant for heavy oil upgrader

8.2 Processes and Energy Use

Petroleum refining essentially consists of trains of fractionation and conversion equipment such as distillation towers and crackers that separate and refine the components of the crude oil feedstocks. Energy is required for fractionation, reaction furnaces, hydrocarbon cracking, compression and other processes. Refineries tend to be unique in terms of their products. For example, not all refiners make lubricants or petroleum coke and therefore have somewhat different processes, equipment and energy intensities.

Refineries generally have a primary crude oil unit, which first distils crude oil into its various fractions characterised by boiling point ranges. A crude unit typically is divided into 2 sequential distillation towers: an atmospheric unit and a vacuum unit. The heavier fraction of crude oil leaving the bottom of the atmospheric unit requires vacuum distillation so that temperatures do not become so high as to degrade the oil.[26]

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[25] Alcan Inc., personal interview, December, 2002

The fractions of crude oil from the crude unit are further refined in downstream processing operations. These processes change the molecular structure of hydrocarbon molecules by breaking them into smaller molecules, joining them to form larger molecules, or reshaping them into higher molecules. Each refinery usually has a different set of downstream processes. The main processes are the following (may not all be employed in Alberta):

- thermal cracking (breaking large molecules into smaller ones);
- coking (cracking of residual fuel into coke and more valuable light fuels);
- catalytic cracking (heat & catalyst breaks larger molecules into lighter molecules);
- catalytic hydrocracking (heat, catalyst & hydrogen breaks very heavy molecules);
- hydrotreating (initial hydrogen treatment process to remove inorganic impurities);
- catalytic reforming (conversion of naphthas into higher-octane aromatics);
- alkylation (acid-catalyzed joining of C3 and C4 molecules to form C7-C8 molecules);
- isomerization (conversion of straight chain C4-C5s to branched chain isomers);
- polymerization (synthesis of high octane C6-C9 from propylene/butylene);
- solvent extraction (e.g. glycol used to selectively remove aromatics from naphthas);
- mercaptan oxidation (conversion of sulphur impurities to SO_x);
- dewaxing (separation of paraffins from lube oils with solvent extraction/chilling);
- propane de-asphalting (separation of asphaltenes from lube oils with propane); and
- bitumen production (heavy bitumen is used to make asphalt products).[27]

Supporting operations are not directly involved in the production of hydrocarbon products, but serve various functions within the refinery. The major supporting operations include: steam generation, cooling water towers, wastewater treatment, gas treatment and sulphur recovery, blowdown system/flare, blending, storage tanks, and loading operations. Some of these are sources of NOx, as well as other CAC emissions.

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[26] Summarised from U.S. EPA Office of Compliance Sector Notebook Project, *Profile of the Petroleum Refining Industry*, 1995.
[27] Ibid.

8.2.1 Energy Use

Refineries use purchased fuels as well as fuels produced by their own operations.. Energy balances for refineries are complex, and there can be issues related to energy accounting for internally generated fuels and purchased fuels used for specific units. Table 44 provides an estimate of fuels consumed by Alberta's refining sector. Some of these fuels contain sulphur that result in SOx emissions. NOx emissions result from combustion.

Table 34: Energy Use in Alberta's Petroleum Refining Sector

(petajoules)

Fuels	**1990**	**1995**	**2000**
Natural gas	18.5	15.3	17.5
Oils	6.7	7.5	7.4
Other fuels	36.2	35.5	54.5
Total	61.4	58.3	79.3

Source: Analysis and Modelling Group/Natural Resources Canada for 1990, 1995. Statistics Canada Report 57-003 for year 2000. Year 2000 estimates may not be on consistent basis as 1990 and 1995 data, since they are from different sources.

8.3 Emission Sources

In petroleum refineries most of the NO_x and SO_x emissions are from fuel combustion exhaust stacks and sulphur recovery unit exhausts. Emissions sources for SO_x and NO_x from petroleum refining sector include:

- boilers;
- furnaces;
- reformers;
- flares;
- fluidized catalytic cracking units (FCC);
- sulphur recovery plants - tail gas vents (SO_x); and
- CO boilers, which can use off-gases from the fluidized catalytic cracking (FCC) units and possibly other processes (SO_x and NO_x).

There can be dozens of furnaces, boilers, dryers, and other equipment from which emissions occur. Typically, there are 5 to 10 stacks representing the majority of emission sources for NO_x and/or SO_x emissions in refineries. Stack emissions and parameter data for each stack and each refinery were not obtained for emission reduction technology costing in this study. An alternative costing approach was applied (see below).

8.4 Reduction Technologies

NO_x emissions may be controlled by installing Low-NOx burners, catalytic reduction systems (SCR) or non-catalytic reduction systems (e.g. SNCR) on furnaces, boilers and heater stacks. In Alberta, SOx emissions arise primarily from the incineration of the tail gas from sulphur recovery units, and to a lesser extent from the combustion of fuels containing sulphur. Current sulphur recovery units remove approximately 98% of the sulphur in the acid gas stream with the remaining 1 to 2% being incinerated to convert the sulphur to SO_x. Further reductions in SO_x emissions require tail gas cleanup systems. Tail gas cleanup units may remove up to 80% of the remaining sulphur in the waste gas stream.

8.5 Costs of Reduction Technologies

Literature sources have been used to estimate the range of reduction costs for refinery sources in Alberta. One source of information has been the costing analysis carried out for refineries in Ontario.[28] These costs were developed using US EPA cost models as identified in the Methodologies section. The cost analysis was applied at the facility level (for each refinery), not at the specific equipment level, since equipment parameter information was not available in time for that analysis. Further collaborative work with the Alberta refineries is recommended to develop more detailed and accurate cost estimates from the many emitting units, if required. Outlined in the tables below are estimates of the cost effectiveness of reducing NO_x and SO_x emissions from various processes within petroleum refineries.

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[28] Cheminfo Services, *Modifications to a Technical Evaluation of Options for Air Pollution Source Control in Selected Industrial Sectors*, DRAFT, Dec. 2002.

Table 35: Estimated Costs to Reduce NO_x Emissions from Petroleum Refineries

($ per tonne reduced)

Control	Emission Reduction	Large Boilers	FCCU	Smaller* Heaters
SNCR	40%	$1,900 - $11,700	Same	Same
SCR	75%	$6,000 - $8,000	Same	$8,000-$10,000
LNB	30%	$2,500- $4,000	na	Slightly higher
LEA	30%	$400 - $700	na	Slightly higher
OFA	40%	$500 - $1,500	na	Slightly higher

* e.g. Crude/Reformer Heaters. Source: Cheminfo Services

Table 36: Estimated Costs to Reduce SO_x Emissions from Petroleum Refineries

($ per tonne reduced)

Control	Emission Reduction	Large Boilers	Smaller Heaters	Sulphur Recovery Unit (SRU)	FCCU/ COB Stack
LSFO	95%	$3,000-$5,000	$4,000		
LSD	90%	$3,000-$5,000			
WGS	90%				$1,000- $2,000
TGTU	95%			$160- $1,500	
DSCA	40%				$1,000- $3,000

WGS - Caustic Wet Gas Scrubbing. TGTU - Tail Gas Treatment Unit (H_2S Scrubbing)
DSCA - DeSOx Catalyst Additive. Source: Cheminfo Services

8.6 Alcan: Carbon Production from Petroleum Coke

Alcan Inc. operates a carbon anode-feedstock production facility in the County of Strathcona. The main piece of equipment at the plant is a kiln. The facility purchases "green" petroleum coke, which is fed to the kiln, to make carbon product. The carbon is sold to producers of carbon anodes that are ultimately used in the production of aluminum. Part of the carbon is sold to Alcan's carbon anode production plants, the rest to other carbon anode producers. The facility is in the process of expanding production capacity, which should increase slowly over time.

8.6.1 SO_x Emissions and Reduction Options

Sulphur is contained in the petroleum coke, a minor portion (10 to 15%) of which is emitted as SO_x. The rest of the sulphur remains in the carbon used to make the anodes (at customer facilities), and is eventually emitted at aluminum smelters, where the anodes are consumed in operations.

8.6.1.1 Switching to Lower Sulphur Petroleum Coke

Lower sulphur petroleum coke feedstock is available at a premium price. In general, it is possible for the facility to reduce its sulphur emissions by a low amount by purchasing coke with lower sulphur content for a slight premium. However, there is limited regional availability of lower-sulphur petroleum coke at the slight premium price. Purchasing this lower sulphur coke would result in approximately a 25% reduction in SOx emissions. It is also possible to purchase more lower sulphur coke for higher premiums. For example, it is possible to purchase coke with 30% less sulphur. However, this would need to be imported from the United States at a much higher premium (5 times the cost of what could be acquired from regional suppliers).

8.6.1.2 Installation of Electric Power Generation Unit

A capital-intensive option, to reduce SO_x emissions by a medium or high level, would be to install a limestone-scrubbing unit. This would require cooling the hot flue gas stream, (1000°C). Cooling the flue gas could be done in such a way as to produce steam that would be used to generate electricity. The company would therefore install a small electric power generating unit and sell excess power. The revenue from the electricity sales would result in a very low net unit cost ($/tonne) for reducing SO_x emissions.

8.6.2 NO_x Emissions and Reduction Options

Alcan's NO_x emissions are largely from the pyro-scrubber. This unit burns off as carbon related particulate matter and volatiles, after the kiln. Alcan could adopt low excess air strategies to reduce NO_x emissions. These could likely achieve 15% reduction, and involve a small capital cost (e.g. less than $0.1 million). There would not be any significant annual operating costs. For high levels of reduction, SNCR and SCR could be applicable at higher capital and annual operating costs.

8.6.3 GHG Emissions and Reduction Options

Approximately 10% of Alcan's petroleum coke feedstock is converted into carbon dioxide. There are no technologies that the company knows of to address its GHG emissions. The facility would have to reduce production, or capture and store the CO_2 underground. Neither option is economically feasible at this time.

8.7 Measurement and Monitoring

A large portion of the SO_x and NO_x emissions from petroleum refineries can be accurately measured with continuous emissions monitoring (CEMs). These could be applied to measure emissions from boilers, large furnaces, vents, etc. However, there may be small sources of NO_x and SO_x from small fuel consuming units or other equipment where CEMs would be very expensive to install. The capital cost of installation of CEMs, at $0.05 to 0.3 million, may be more expensive than the cost of emission reduction controls at some small emitting sources. Combustion sources of GHG emissions could be accurately calculated based on fossil fuels consumed and application of standard emission factors for each fuel.

9. Upstream Oil and Gas

9.1 Scope of Upstream Oil and Gas Sector

Alberta's large and complex upstream oil and gas sector is classified under SIC 07, and encompasses the following groups of economic activity:

- Non-conventional crude oil mining and production; and
  - Oil sands mining, extraction and upgrading
  - Pipelines
- Conventional crude oil and natural gas.
  - Oil exploration, wells and separation facilities;
  - Natural gas exploration, wells and processing facilities; and
  - Pipelines

9.2 Non-Conventional Oil Sands and Upgraders

There are currently less than half a dozen oil sands projects (large thermal or mining, excluding pilot plants). However, more than 20 operations are planned for Alberta by 2010.[29] There are at least two general technologies applied to mining the oil sands. One method is to use surface mining equipment to collect and transport the sands containing the oil to an extraction and upgrading facility. Another method is similar to conventional methods in that it produces from wells. An example of this kind of production (called *in situ* or "in place") is steam assisted gravity drainage (SAGD) technology. This technology involves generating and injecting steam underground to enable the bitumen to be pumped to the surface.

Some operations may upgrade the produced bitumen before refining. The Suncor, Syncrude and Shell operations all include upgrading facilities to change bitumen to lighter synthetic crude oil (SCO).

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[29] The list of facilities is contained in the accompanying Appendix C, profiling emissions in Alberta.

9.2.1 Emission Sources

The major sources of NO_x, and SO_x emissions from oil sands mining and upgrading activities include:

- fuel combustion (notably SO_x from oil and coke, NO_x from all fuels);
- sulphur recovery facilities (SO_x);
- power (steam/electricity) generation equipment (mostly NOx, some SOx; and
- operation of mine vehicles and equipment (mostly NOx).

There are hundreds of emission sources at oil sands projects. These include the operation of mine fleets, steam generation units, cogeneration units, furnaces, and other equipment used for bitumen mining, extraction and upgrading. For each of these emission sources, the number of individual pieces of equipment at the facility can range from a few to dozens. The mine fleets, which are substantial sources of NO_x are one such example. Mine fleets can consist of dozens of different vehicles, such as dozers, heavy haulers, shovels, and heavy duty trucks. Similarly, on the extraction and upgrading side there may be one to a dozen process boilers or heaters at the site.

Table 37: Major Emission Sources for Total Oil Sands

(Estimated Based on Existing and New Oil Sands Projects Accounting for over 90% of the Forecast of 2010 SO_x and NO_x Emissions)

Source Category	NO_x		SO_x	
	(kt)		(kt)	
Stationary Combustion Equipment (boilers, heaters, cogeneration units, sulphur recovery plants, etc.)	79	54%	150	98%
Mine fleet	55	38%	1	1%
Cogeneration units	11	8%	1	1%
Total estimated from specific units (kt)	145		152	
2010 Forecast Emissions (kt)	162		159	
Percent of 2010 Forecast Emissions	90%		96%	

A major source of NO_x emissions from SAGD operations are the steam generators, which consume fossil fuels and result in combustion related emissions. Natural gas in the fuel most often used for steam and power generation, however the use of oil and even coal is possible. Energy is also required for upgrading operations. In some cases, companies are installing cogeneration facilities at the mine site to generate electricity as well as steam. Emissions (and costs to reduce) from these units are included as part of the oil sands development.

Sulphur recovery plants, which will typically recover over 98% of the sulphur in the crude bitumen, are an important source of SO_x emissions. The small amount (less 1%) of un-recovered sulphur is oxidized to SO_x before being emitted.

Emissions from each of the sources associated with the existing and new oil sands projects have been gathered from Environmental Impact Assessment reports. These reports provide a fairly detailed listing of emissions, by source, and have been used to estimate the costs of emission reduction technologies.

9.2.2 Reduction Technologies

The NO_x and SO_x emission reduction technologies assumed to be applicable for stationary sources are the same technologies as applied in other sectors. SCR and SNCR units are applicable for NO_x reduction. It has also been assumed that Low-NO_x burners and other technologies that can achieve low levels of reduction are not applicable to this sector because these technologies are already being employed. For SO_x reduction, it has been assumed that limestone scrubbing and dry lime scrubbing systems would be applicable. These can achieve high levels of reduction but at high cost and may not be applicable for small sources. Therefore, the costing analysis only addresses large SOx emissions sources, which constitute 90% of the SOx emissions.

9.2.2.1 NOx Control Technologies for Mobile Sources

The control of NOx emissions from the mining fleet requires technologies that can be mounted on large-scale, heavy-duty mobile equipment. Engine ratings for this heavy-duty equipment typically range from 2,000 hp (for smaller trucks) to 28,000 hp (for older draglines). The smallest of these engines is more than five times larger than the engine on an average on-road, heavy-duty diesel truck (400 hp). To date, no proven NOx control technologies have been developed for these large-scale diesel engines. In two separate initiatives, the U.S. EPA is finalizing stringent NOx emission standards for On-Road diesel engines that will come into effect by 2007 and is also developing Tier 3 standards for large Off-Road diesel engines. These initiatives may accelerate the development of NOx control technologies for these high-end applications. In background work by the U.S. EPA for the development of these standards, the three most-promising NOx control options have been identified as: selective catalytic reduction (SCR); fuel-water emulsions; and NOx adsorbers.[30]

Fuel-water emulsions offer low cost NOx reductions of 5-30% since the presence of water lowers the combustion temperature. However, loss of power rating is an issue with fuel-water emulsions.

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[30] U.S. EPA, Office of Transport & Air Quality, December 4, 5, 2002 interview.

The NOx adsorber is an advancement on the conventional three-way catalyst design that can achieve very high NOx reduction levels (>90%), even under the typical lean-burn conditions of diesel engines. An alternating mode operation (60 seconds lean-burn, then 2-3 seconds rich-burn) is used to remove CO and non-methane hydrocarbons (NMHCs) in the first mode, and then remove NOx in the second mode. In the lean-burn mode, NOx is temporarily adsorbed on a substrate in the form of a nitrate. In the short rich-burn mode, virtually all the stored NOx is released and reduced in a fuel rich environment. The equipment and material costs for NOx adsorbers for typical 400-hp On-Road heavy-duty diesel vehicles are estimated to cost about C$6,000 to $10,000 per unit. Retrofitting costs are unknown. This technology was not incorporated into the costing analysis.

9.3 Costs of Reduction Technologies

The costing analysis for sources at the oil sands facilities relied on company input on costs, as well as US EPA cost models, which required application of simplifying assumptions. Costs for fuel combustion sources were developed based on their size/rating. For example, cogeneration units were sized based on the amount of thermal energy required for their operation (e.g. maximum GJ/hour). A similar approach was applied to boilers, furnaces and other sources.

In general, the cost effectiveness ($/tonne-reduced) for NOx reduction from fuel combustion equipment (excluding mobile sources), is higher among new oil sands facilities than among similar sources in other sectors. The reason is that the new equipment generally has lower NOx emission rates than older equipment in place in other sectors.

Table 38: Summary of Costs for NOx and SOx Reductions at Oil Sands and Upgraders

(SCR Costs Include Mining Fleet)

	Units	SNCR	SCR	LSFO	LSD
Technology emission reduction potential		45%	85%	95%	90%
Actual emission reductions for applicable sources within industry	(kt)	37	123	130	124
Reduction potentially achieved with technology (as percent of total source-specific emissions)		25%	85%	86%	81%
Average annualized capital plus O&M costs	($/tonne -reduced)	$2,484	$4,096	$2,632	$2,200

Technologies that can address SOx emissions include wet limestone scrubbing and lime spray drying. These technologies are more applicable to large sources and therefore the costing analysis for SOx only addressed stationary sources with over 500 tonnes/year of

SOx emissions (and where sufficient data was available for cost estimating purposes). There were 23 such sources (out of approximately 110) among the oil sands projects, which accounted for 90% of the SOx in the industry, or about 138 kilotonnes/year of emissions.

9.3.1.1 Costs for Mine Fleet Emission Reductions

SCR systems have been selected for cost modelling of the mining fleet, because of availability of cost information, high reduction efficiency achieved by the technology, commercial viability, and no adverse effects on engine performance.

SCR systems have been used successfully on stationary diesel engines and marine diesel engines to reduce NOx emissions by greater than 85%. SCRs are currently being developed and tested on mobile diesel engines, but they have yet to be commercialized. SCR equipment costs for mobile diesel engines are estimated at C$150 per kW mechanical power rating. The installation premium is conservatively estimated at an additional 50% of capital cost.[31] SCR operating costs, which include urea solution, catalyst replacement and maintenance, are estimated at an average of C$4.8 per MWh.[32]

Using the power ratings of specific mobile equipment within the Syncrude's mining fleet as a case study, and Syncrude's annual NOx emissions from its fleet, an SCR capital cost of C$4,105 per tonne of uncontrolled NOx emissions was determined. Similarly, an average SCR annual operating cost of C$647 per tonne of uncontrolled NOx was determined. Annualized capital costs plus annual operating & maintenance costs are $1,328 per tonne-NOx-reduced.

Reducing NOx emissions from the vehicle fleet can be cost effective versus some stationary sources. One influencing factor is the amount and concentration of NOx from the fleet vents, relative to the fuel consumed. The rate of NOx emissions per unit of energy input for large diesel vehicles can be 10 times the emission rate per unit of fuel consumed in furnaces, boilers and similar stationary equipment.

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[31] Caterpillar Inc., Personal interview, December 4, 2002

[32] *The Motor Ship magazine*, April 2000. Data reported by Siemens, a leading SCR manufacturer. Similar to estimates provided by other SCR suppliers (e.g. ABB).

9.4 Conventional Oil and Gas

The upstream oil and gas sector is comprised of a complex network of facilities and operations used to develop, produce, gather, treat/process and transport oil and gas to market (i.e., to refineries, petrochemical plants, distribution systems and consumers). This infrastructure varies in size, age, design and operating characteristics, and comprises millions of potential sources of atmospheric emissions. These sources range from small fugitive leaks on valves and fittings to large point sources such as sulphur recovery incinerator stacks.

9.4.1 Emission Sources

Natural gas production, processing and transmission accounts for the majority of the NOx, SOx and GHG emissions in Alberta. Generally, natural gas production and process require more energy (than oil) and therefore these activities account for nearly three-quarters of the NOx emissions. While the great majority of the sulphur contained in the crude gas is recovered, the small unrecovered portion translates into significant SOx emissions.

Table 39: Major Emission Sources for Upstream Oil and Gas

Source Category	NO_x	SO_x	GHG
Gas production	46%	0%	29%
Gas processing	30%	74%	27%
Gas transmission	4%	0%	10%
Well servicing and testing	1%	13%	1%
Conventional oil production	8%	12%	10%
Heavy oil production	0%	0%	14%
All other sources	11%	1%	9%
Total	100%	100%	100%

Source: Clearstone Engineering

Practically all of the sources of NOx, SOx and GHG emissions have been addressed in the emission reduction technology costing analysis for this project.

9.4.2 Reduction Technologies

Many emission reduction technologies have been considered for NO_x, SO_x and GHG emissions from the upstream oil and gas sector. These range in reduction efficiency and cost depending in the control system selected. A list of control options considered, the primary pollutants targeted and control efficiency is summarized in the table below.

Table 40: Controls Considered for Upstream Oil and Gas

Emission Reduction Technology	Target Pollutant	Control Efficiency (%)
Conversion from fuel gas to air for instrumentation	GHG	80
Installation of catalytic convertors on engines	NO_x	45 - 80
Compressor load optimization	NO_x, GHG	15, 15
Destruction of dehydrator off-gas	GHG	15
Replace field dehydration with methanol injection	GHG	10
Leak detection and repair	GHG	~50
Acid gas injection	SO_x, GHG	~100
Flare gas recovery	SO_x, GHG	99, 90
Conversion from DEA sweetening to MDEA	NO_x, GHG	5, 5
Field vs regional upgraders	NO_x, GHG	5, 5
Heavy oil casing gas conservation	GHG	75
Heavy oil casing gas flaring vs. venting	GHG	85
Solution gas vapour recovery	GHG	75
Flaring vented waste gas	GHG	40
Upgrade to high efficiency flares	NO_x, GHG	30, 5
Waste gas utilization – conventional generators	GHG	20
Waste gas utilization – micro turbines	GHG	40
Well tests to pipeline	NO_x, GHG	~100, ~100
Decreased well test duration	NO_x, GHG	50, 50
Destruction of well test gas	GHG	80
Selective catalytic reduction (SCR) for heaters/boilers	NO_x	85
Selective non-catalytic reduction (SNCR) for heaters/boilers	NO_x	45
Low excess air, other operational, instrumentation improvements	NOx	15
Wet limestone scrubbing (large sources >500 tonne/year of SOx)	SOx	95%
Dry lime scrubbing (large sources >500 tonne/year of SOx)	SOx	90%

9.4.3 Costs of Reduction Technologies

There are opportunities in the conventional oil and gas sector to achieve emission reductions at relatively low costs. For example, the adoption of catalytic convertors on compressors based on internal combustion engines offers a relatively low cost NOx technology. There are also opportunities for improvement process optimization and control instrumentation improvements, although many facilities have already implemented such practices. Opportunities still exist for underground acid gas injection, as a technology that addresses both SOx as well as GHG emissions, although, again this technology has been applied. Low-NOx burners are applicable to a large portion of the population of steam generating equipment in the sector. Achieving higher levels of reduction would involve potential adoption of SNCR or SCR systems. Costs for these technologies applicable to various quantities of the pollutants are shown in the table below.

Table 41: Average Costs For NOx and SOx reductions for Conventional Upstream Oil and Gas Emissions

Technology		Catalytic Convertors For Compression Engines	SNCR	SCR	LNB	Operational Improvements Instrument Changes	LSFO	LSD
	Units	NOx	NOx	NOx	NOx	NOx	SOx	SOx
Technology emission reduction potential		40-80%	45%	85%	41%	15%	95%	90%
Actual reductions related to costs	(kt)	110 (assumes 75% reduction)	131	248	120	44	229	217
Average annualized capital, O&M costs	($/tonne-reduced)	$73	$1,711	$2,931	$1,531	$253	$2,663	$2,509

Source: Clearstone Engineering

Cost estimates for reducing SOx emissions have been estimated based on the hypothetical adoption of wet limestone scrubbing systems and lime spray drying systems. Costs for these technologies were developed using US EPA cost algorithms (and adoption of simplifying assumptions for stack parameter data). Actual costs were developed for 63 facilities where the SOx emissions rates were over 500 tonnes/year, and for which some emissions information was available. These 63 facilities accounted for 70% of the total SOx emissions from upstream sources.

There are also opportunities for GHG emission reductions at negative net costs. That is, there is the potential adoption of reduction technologies that would pay for themselves (given the specific cost of capital assumed for the purposes of this costing analysis) as a result of fuel consumption savings, conservation of previously vented or flared natural gas or the elimination of electric power loads. Projects with net negative costs generally involve conservation of natural gas. An example of this type of project is heavy oil casing gas conservation, which has a net annualized savings of $1.36 per tonne of GHG-reduced.

9.5 Measurement and Monitoring

9.5.1 Conventional Oil and Gas

Emissions from the conventional oil and gas sector arise from a wide variety of large and small sources. Many of the large sources have continuous emission monitoring (CEM) systems already installed, especially for SO_x emissions from sour gas processing plants equipped with sulphur recovery units.

However, most upstream oil and gas emission sources, representing the majority of NO_x, VOC and GHG (e.g. for methane) emissions from the industry, have no continuous emission monitoring system installed. Emissions from these sources are rarely measured. Instead, emissions are typically estimated based on a surrogate, such as fuel consumption, and standard emission factors.

To put this in perspective, in addition to the handful of stacks equipped with continuous emission monitoring systems, NO_x emissions result from fuel consumption in over 3,000 compressors, over 5,000 gas fired heaters/boilers, and over 5,000 flare stacks which are widely dispersed throughout the province.

9.5.2 Oil Sands

Measuring and monitoring SO_x and NO_x emissions from large stationary sources boilers, sulphur recovery plants, cogeneration units, furnaces and other such equipment would be technical possible at oil sands facilities.

Measuring emissions from heavy mobile moving equipment may be more challenging and costly. To yield meaningful results, measurements would have to be made under actual operating conditions, taking into account actual load characteristics and fuel composition of the fleet. This requires special mobile test equipment and has not, for the most part, been undertaken. Measuring the NOx emissions from the mobile fleet may need to take into account equipment start-up, low power use, high power use, temperature and other variables that could effect emissions.

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11. Alberta Industrial Facilities Contacts For the Study

(Primary contacts. Additional people contacts were contacted to collect necessary information)

Sector/Company	Location	Main Contact*/Position
CEMENT		
Inland Cement	Edmonton	Brent Korvanick (Environmental Affairs Coordinator)
Lafarge Canada	Exshaw	Brad Watson (Environmental Manager)
CHEMICALS		
Alcan	Edmonton	Doug Burton (Plant Manager)
Agrium	Carseland	Roger Warren (Process Engineer)
Agrium	Fort Saskatchewan	Geoff Milacwarth (Process Engineer)
Agrium	Redwater	David Craig (Process Engineer)
Alberta Envirofuels	Edmonton	Harry Jarvelin (Environmental Manager)
AT Plastic In	Edmonton	Peter Bieman (Environmental Health & Safety)
Canadian Fertilizers Limited	Medicine Hat	Ron Wendling (Environmental Manager)
Cancarb Limited	Medicine Hat	Sam Czember (Environmental Manager)
Celanese	Edmonton	Brian Helpin (Environmental Department)
Dow Chemical	Fort Saskatchewan	Ken Tsang (Director, Health & Safety)
Marsulex Sulphides	Fort Saskatchewan	Ross Stacey (Environmental Manager)
Methanex	Medicine Hat	George Wellan (Environmental Manager)
Novacor Chemicals Ltd.	Joffre	Jim Dixon (Environmental Manager)
Orica Canada Inc	Carseland	David Hines (Technical Supervisor)
Shell Canada	Scotford	Carl Blonski (Health & Safety Engineer)
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Sector/Company	Location	Contact/Position
ELECTRIC POWER		
AES	Edmonton	Jason Keith (Environment Department)
ATCO Power	Edmonton	Joe Kostler (Manager – Environment, Health & Safety)
EPCOR	Edmonton	Joel Nodelman (then Manager, Sustainable Development)
Fording	Edmonton	Dermot Lane (Environment Department)
TransAlta	Calgary	Don Wharton (Environment Department)
PULP AND PAPER		
Alberta-Pacific Forest Industries Inc	Boyle	Shaun McNamara (Environmental Specialist)
Daishowa-Marubeni Int.	Peace River	Tom Tarpey (Environmental Manager)
Weldwood of Canada	Hinton	Joanne Volk (Technical Services Manager
Weyerhaeuser Canada	Grand Prairie	Edward Lamy (Environmental Department)
WOOD PRODUCTS		
Ainsworth Co. Ltd.	Grand Prairie	Doug Bagget (Safety and Environmental Manager)
Alberta Plywood Ltd.	Edmonton	Jerry Leslniewski (Plant Manager)
Boucher Bros. Lumber Ltd.	Nampa	Barry Heinen (Environmental Department)
Buchanan Lumber	High Prairie	John Broderick (Mill Manager)
Canadian Forest Products Ltd	Grand Prairie	Pat Ottenbreit (Environmental Officer)
Hi-Atha Sawmill Ltd	Hinton	Tom Stoddart (Chief Engineer)
La Crete Sawmills Ltd	La Crete	Wally Wiebe (Operations Manager)
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UPSTREAM OIL & GAS		
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* Additional contacts were made at some of the facilities.

12. Crosscutting Emission Control Technologies

12.1 Introduction

This section describes some of the general crosscutting technologies that are available to address emissions of NO_x, SO_x and CO_2 from facilities in industrial sectors. In some instances, these technologies are widespread and have often been used by various industrial facilities. In other instances, some of these technologies (e.g. CO_2 capture and storage) are available, however for various reasons have not been used nearly as often as other technologies (e.g. low NO_x burners). Some of the technologies described in this section are generally only applicable to one sector (e.g. electric utilities). The reader is referred to the individual industrial chapters of this Appendix for more detailed descriptions of the technologies that were identified by industry as the preferred choice to achieve the emission reduction contemplated therein.

Table 42: Typical Emission Reductions Achieved with Crosscutting Emission Reduction Technologies

Technology	SO_x	NO_x	CO_2
NOx Technologies			
Selective Catalytic Reduction (SCR)		85%	
Selective Non-Catalytic Reduction (SNCR)		45%	
Low Excess Air (LEA)		15%	
Low NO_x Burners (LNB)		20-60%	
Low NO_x Burners Plus Overfire Air (LNB+OEA)		25-70%	
Low NO_x Concentric Firing System (LNCFS)		15-55%	
Natural Gas Reburning (NGR)		60%	
SOx Technologies			
Lime Injection Multistage Burner (LIMB)	55%-75%		
Lime Spray Drying (LSD)	90%		
Limestone Scrubbing (Forced Oxidation) (LSFO)	95%		
LIFAC Sorbent Addition	75%		
CO_2 Technologies			
CO_2 Capture and Storage			50-100%
Biomass-Fired Co-Generation (BCC)			90%+
Natural Gas Combined Cycle (NGCC) for electricity generation			50% vs. coal simple cycle

Source: Cheminfo Services

12.2 NO_x Reduction Technologies

There are four different mechanisms that produce NO_x emissions within various industrial facilities, specifically: (i) oxidation of N in combustion air (thermal NO_x); (ii) oxidation of N in fuel (fuel NO_x); oxidation of N in raw materials used (feed NO_x) and (iv) prompt NO_x. Thermal NO_x formation occurs when oxidising flames reach a certain temperature. It has been suggested that once the temperature exceeds 1,200°C, significant amounts of thermal NOx are formed. Feed NO_x and fuel NO_x emissions are a result of the oxidation of nitrogen compounds in the raw materials and fuel respectively. Prompt NO_x is formed when fuel-derived radicals react with N_2 in hydrocarbon flames. Outlined below are the major crosscutting technologies that can be used to reduce NO_x emissions across several industrial sectors.

12.2.1 Selective Catalytic Reduction (SCR)

SCR systems expose exhaust gas to ammonia (or urea) and a catalyst in the temperature range of 300-400°C, which reduces NO and NO_2 to N_2. Ammonia is most often injected to produce an NH_3:NO_x molar ratio of 1.05-1.1:1, which will result in an ammonia "slip" of about 10 ppm in the exhaust. The extent of NO_x removal from the exhaust gas depends on several variables, such as the temperature, NH_3: NO_x molar ratio, and the flue gas residence time (or the space velocity) used in the catalyst bed. Experience with SCR systems indicates that NO_x removal efficiency is typically in the 70-90% range.

Several materials have been used for catalysts in SCR applications. Titanium dioxide and vanadium pentoxide are those materials most commonly used. Zeolite-based catalyst materials have also been utilised and can be used at higher operating temperatures than the metal-based catalysts.

An issue associated with the use of SCR systems is that the preferred exhaust gas temperature range may be higher than that typically observed in some facilities, especially in plants using heat recovery systems or baghouses for particulate collection. However, it may be possible to reheat the exhaust gas and then direct the gas into the SCR system. Other issues associated with the application of SCR systems are focused on the high dust concentration in the gases, the catalyst dust removal techniques, lifetime of the catalysts and total capital costs.

Since the catalysts used in the SCR system also remove hydrocarbons, emissions of VOCs and dioxins/furans are also reduced. If the exhaust gas has to be reheated, this will result in an increase in CO_2 emissions (as well as additional fuel costs).

12.2.2 Selective Non-Catalytic Reduction (SNCR)

SNCR typically involves injecting ammonia or urea compounds into the exhaust gas (ideally in the temperature range of 870-1,090°C) in order to reduce NO and NO_2 to N_2. The temperature range is critical to the effectiveness of SNCR due to fact that no catalyst is used to facilitate the reaction. The reagents at higher temperatures will form additional NOx, while at lower temperatures the reaction process is not as efficient and significant quantities of unreacted ammonia will escape (i.e. ammonia slip). Ammonia slip also occurs when the molar ratio of NH_3 to NO is too high.

NO_x emission reductions achieved with SNCR technology varies based on several factors, for instance the temperature, residence time, as well as ammonia and NO_x concentrations in the flue gas. If ammonia is injected at an NH_3: NO_x proportion of 1 to 1.5, NO_x emissions can be reduced by 60-80%. However, when a molar ratio of 0.5 is used, NO_x emission reductions of approximately 40% are achieved. Another factor affecting NO_x reduction efficiency of SNCR systems is the flue gas residence time in the appropriate temperature window. The more accurate the existing gas temperature profile is for the process, the more effective the SNCR system will be.

The most common concerns reported with ammonia or urea based SNCR systems are the build-up of ammonium bisulphite scale (especially when sulphur containing fuels are used) and the conversion of NO to N_2O (more prevalent in systems using urea). In addition, ammonia slip can lead to significant levels of ammonia emissions, which can result in increased opacity from the system, potentially violating provincial permit requirements.

12.2.3 Low NO_x Combustion (LNC)[33]

Low NO_x combustion (LNC) as described in this section includes techniques used to delay or modify the combustion process within a boiler or furnace as a means to reduce NO_x emissions. The production of NO_x during combustion depends on several factors, including: boiler design; size; operating parameters; and fuel composition. Low NO_x technologies reduce the oxidation of atmospheric nitrogen (N_2) and fuel-bound nitrogen by modifying flame geometry and the rate of air/fuel mixing.

There are two particular techniques addressed in this section that reduce the levels of NO_x formed: (i) lowering excess air in the furnace/boiler; and (ii) staging the combustion air. Lowering the excess air in the boiler reduces both fuel and thermal NO_x emissions, while staging introduces the combustion air in two or more distinct zones. Because of the wide variations in boiler characteristics and NO_x levels, the applicability of combustion modification technologies for reducing NO_x is boiler/furnace-specific.

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[33] U. S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory, *Integrated Air Pollution Control System Version 5.0 Volume 2: Technical Documentation*, June 1996

The NO_x control technologies discussed in the following sections include four major combustion controls: (i) low excess air (LEA); (ii) low NO_x burners (LNB); (iii) overfire air (OFA) alone or with LNB (LNB + OFA); and (vi) low NO_x concentric firing systems (LNCFS).

12.2.3.1 Low Excess Air (LEA) [34]

Low excess air is simply the reduction of excess airflow to the furnace/boiler relative to a typical furnace/boiler operation. There is a limit to the extent to which airflow to the furnace/boiler can be reduced, as incomplete combustion results which increases carbon monoxide and smoke formation.

There are several mechanisms to consider when the total excess air is reduced. Firstly, the local flame zone concentration of O_2 is reduced, thus decreasing thermal NO_x emissions and fuel-bound NO_x emissions. Secondly, the fuel-to-air mixing ratio is reduced, further decreasing fuel-bound NO_x emissions. However, low excess air does not reduce the fuel-to-air mixing as much as staging the combustion air. Therefore, LEA is not as effective for reducing fuel NO_x emissions of higher-nitrogen fuels such as coal or residual oil.

There is an economic incentive to operate with LEA as the furnace/boiler efficiency is increased due to the higher combustion heat transfer. This has an economic benefit of reducing fuel requirements. Low excess air is applicable to all furnace/boiler types and can reduce NO_x emissions by up to 25 percent.

12.2.3.2 Low NO_x Burners (LNB)

Low NO_x burners involve the injection of fuel and air into the system through concentric tubes. In this system, the primary air proportion is reduced by approximately 20-25% over that which occurs in traditional burners. Axial air is injected at high momentum in the outer channel, while the fuel may be blown through the middle channel. A third channel is used for swirl air. Low NOx burners can be used with many different types of fuel, for instance coal, oil, natural gas, propane, etc.

Low-NO_x burners are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The staged combustion achieved with low-NO_x burners results in longer, less intense flames, lower flame temperatures and reduced thermal NO_x formation. Some low-NO_x burners produce a low-pressure zone at the burner centre through the injection of fuel at high velocities along the burner edges. The low-pressure zone results in the recirculation of hot combustion gases that are retrieved through an internal reverse flow zone around the extension of the burner centreline. The recirculated combustion gas is deficient in oxygen and as a result the combustion of the fuel in the first stage takes place in an oxygen-deficient zone before the fuel is diluted in the secondary air.

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[34] Ibid.

Some of the collateral impacts of using low-NO_x burners are that due to the tendency to produce divergent flames, SO_2 emissions can be increased.

12.2.3.3 Overfire Air and Low NO_x Burners Plus Overfire Air[35]

Overfire air is a method of staging the combustion air by diverting a percentage (typically 5 to 20%) of the total combustion air from the burners to ports above the top burner level. Note that there is no change in the total amount of combustion air fed to the furnace. NO_x emissions are limited by two mechanisms: partially delaying and extending the combustion process, resulting in less intense combustion and cooler flame temperatures thereby suppressing thermal NO_x formation; and lowering the concentration of air in the burner combustion zone where volatile fuel nitrogen is evolved, thereby lowering fuel NO_x formation.

OFA ports without LNBs are generally only added to tangential-fired units to achieve up to 35% emission reduction. For wall-fired boilers, overfire ports are generally installed in conjunction with LNB to achieve up to 60% reduction.

12.2.3.4 Low NO_x Concentric Firing System (LNCFS)[36]

LNCFS is a method of controlling flame stoichiometry applicable only to coal-fired tangential boilers. LNCFS modifies the burner assemblies from which fuel and air are injected into the furnace by decreasing the level of primary air and directing secondary air away form the fireball and toward the furnace wall. This has the effect of forming two concentric circles: a fuel-rich zone in the inner circle; and a fuel-lean zone in the outer circle. The fuel is directed toward the centre of the furnace, which has a lower O_2 concentration, while the bulk of the O_2 remains near the waterwalls. Therefore, combustion is delayed for a short time, favouring the formation of N_2 instead of NO_x. Subsequently, both the fuel- and air-rich zones are mixed due to bulk mass transport, while the balance of the combustion air is injected through OFA ports located above the burners to complete the combustion process.

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[35] Ibid.

[36] Ibid.

Three levels of LNCFS are available: (i) level I uses "close-coupled" OFA in which OFA ports are installed at the top of the existing windboxes, achieving up to 35% NO_x reduction; (ii) level II uses "separated" OFA, in which OFA ports are installed in new windboxes above the existing windboxes, achieving up to 45% control; and (iii) level III uses both close coupled and separated OFA and achieves up to 55% control.

12.2.4 Natural Gas Reburning (NGR)[37]

Natural gas reburning (NGR) replaces a percentage (15-20%) of the main fuel from the primary combustion zone with natural gas injected downstream of the primary combustion zone. This forms a reducing zone in which NO_x is reduced to nitrogen. Combustion air for the reburning fuel (natural gas) is injected further downstream.

A critical factor which controls NO_x emission reductions in this technology is the residence time in the reburn zone, the area where the natural gas is combusted. This is affected by the placement of reburn injectors and OFA ports, and ultimately furnace size and geometry. Minimisation of the residence time can be achieved through complete mixing of the reburn fuel and combustion gases from the main combustion zone. Other critical factors for the destruction of NO_x include the temperature and oxygen levels in the burnout zone.

In addition to NO_x control, SO_x reductions may result from replacing a portion of the fuel with cleaner natural gas.

12.3 Acid Gas/SO_2 Controls

12.3.1 Lime Injection Multistage Burner (LIMB)[38]

Lime Injection Multistage Burner (LIMB) is a process whereby SO_2 and SO_3 are reacted with calcium oxide to form calcium sulphite and sulphate. The calcium oxide for these reactions is formed through the high-temperature decomposition of powdered calcitic hydrate, injected into the upper furnace of a coal-fired burner. Humidification through the injection of water downstream of the air heater enhances the reaction of SO_2 with the sorbent to achieve up to 70% SO_2 removal. The extent of SO_2 removal that can be achieved depends on the flue gas composition, temperature, quench rate in the reaction zone, sorbent composition and surface area, the calcium-to-sulphur ratio (Ca/S), whether normal (cooling the flue gas to within 45°C of the saturation temperature) or deep

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[37] Ibid.
[38] Ibid.

(cooling the flue gas to within 5°C of the saturation temperature) humidification is used, and degree of mixing between the sorbent and the flue gas.

The gas temperature at the point of sorbent injection is a critical variable affecting the calcination and sulphation reactions. Peak SO_2 removal for most sorbents occur between 980°C and 1200°C, above which sorbent deactivation occurs, and below which reaction rates are significantly reduced. In most boilers, these temperatures are found in the upper furnace. Other critical variables include the extent of sorbent/flue gas mixing. Thorough mixing is achieved through rapid distribution of the sorbent over the full boiler cross-section.

12.3.2 Lime Spray Dryer (LSD)[39]

The lime spray dryer (LSD) is a conventional spray dryer vessel attached to the air heater exit stream, in which an atomised slurry of lime and recycled solids is contacted with the flue gas. Sulphur oxides in the flue gas react with the alkali in the slurry as follows:

Lime Hydration: $CaO + H_2O \rightarrow Ca(OH)_2$
SO_x Reactions: $Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O + 1/2\ H_2O$
$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \cdot 2\ H_2O$
Sulphite Oxidation $Ca(OH)_2 + SO_2 + H_2O + 1/2\ O_2 \rightarrow CaSO_4 \cdot 2\ H_2O$

The water entering with the slurry is flashed off, thereby decreasing the flue gas temperature and raising the moisture content. As in the LIMB process, a particulate matter control device downstream of the spray dryer is necessary to remove the dry solids and fly ash that did not fall out in the vessel. A recycle stream back to the slurry feed system consists of some collected reaction products and fly ash solids. The remaining solids are disposed of as solid waste. LSD systems can achieve SO_x reduction efficiencies of above 90%.

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[39] U.S. Environmental Protection Agency Office of Research and Development, *Coal Utility Environmental Cost (CUECOST) Workbook User's Manual Version 1.0*, 1999

12.3.3 Limestone Scrubbing Forced Oxidation (LSFO)[40]

Limestone scrubbing forced oxidation (LSFO) systems contact the flue gas with a slurry containing approximately 15% calcium carbonate and calcium sulphate solids. SO_2 absorption occurs, producing an aqueous sulphite in the liquid phase. The sulphite is oxidised to sulphate downstream by forced air injection in a separate recirculation tank. The overall result is close to 100% conversion of calcium sulphite to calcium sulphate, through the following series of reactions:

SO_2 Reaction: $CaCO_3\,(s) + SO_2\,(g) + 1/2\ H_2O \rightarrow CaSO_3 \bullet 1/2\ H_2O + CO_2$

Sulphite Oxidation: $CaSO_3 \bullet 1/2\ H_2O + 1/2\ O_2 + 3/2\ H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$

The slurry produced by the FGD system can be thickened and pumped directly to a gypsum stack for final disposal, vacuum filtered or centrifuged for landfill disposal, or washed and dewatered for commercial wallboard production.

Due to the high reaction rate and conversion in the aqueous phase, the critical variables affecting the SO_x reduction are the contact and subsequent absorption between the flue gas and slurry. LSFO systems can result in better than 95% SO_x removal efficiencies.

12.3.4 LIFAC Sorbent Addition

The LIFAC technology involves the introduction of pulverized limestone into the upper part of the boiler near the superheater where the limestone absorbs some of the SO_2 in the flue gas. The limestone is transformed into calcium oxide and can be further used for additional SO_2 capture downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO_2 capture. Upon leaving the chamber, the sorbent is separated from the flue gas through the use of an electrostatic precipitator (ESP). To increase efficiency, the sorbent material from the reactor and electrostatic precipitator are recirculated back through the reactor. SO_2 emission reductions in the 60-85% range are expected with the LIFAC technology. There are 10 full-scale LIFAC units in operation in Canada, China, Finland, Russia, and the United States.[41]

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[40] Ibid.

[41] U.S. Department of Energy's Clean Coal Technology Compendium, *LIFAC Sorbent Injection Desulfurization Demonstration Project.*

12.4 CO_2 Reduction Technologies

12.4.1 CO_2 Capture and Storage

There are different types of technologies that can capture potential CO_2 emissions, namely: (i) carbon absorption; (ii) carbon adsorption; (iii) cryogenics; and (iv) membrane systems.

The capture of CO_2 represents only a portion of the problem. A significant factor that contributes to the overall cost effectiveness of applying CO_2 capture technology is how the CO_2 is dealt with after it is captured including how it is transported from the capture to use site. Options include: enhanced oil recovery or other forms of utilisation; geological storage; and ocean storage. However, effective utilisation options are not plentiful. For example, it has been estimated that only 1 to 5% of the total CO_2 emissions from power plants could be used effectively.

Carbon absorption, for the most part, employs a continuous scrubbing system. There are three basic types of carbon absorption systems, being chemical, physical and hybrid. Chemical absorption operates by reacting the CO_2 with chemical solvents (in an absorption tower) in order to form a weakly bonded intermediate compound which in turn is broken down by applying heat resulting in a regeneration of the original solvent and a CO_2 stream. Typical solvents used in carbon absorption chemical systems are amine or carbonate based, such as monoethanolamine (MEA), diethanolamine, ammonia and hot potassium carbonate.[42]

MEA is currently the absorption technology of choice for capturing CO_2 from some fossil fuel power plants. In comparison to other solvents, MEA has a strong attraction for CO_2. MEA also has a relatively high carrying capacity (amount of CO_2 absorbed per unit volume of solvent), which leads to lower capital and operating costs.[43]

CO_2 can also be physically absorbed in a solvent and then be regenerated using heat and/or pressure. Typical solvents used for physical absorption are Selexol (i.e. dimethylether of polyethylene glycol) and Rectisol[44] (i.e. cold methanol) which are applied at high pressure. The Selexol physical solvent process has been frequently specified for coal gasification applications. Hybrid carbon absorption processes are usually composed of a number of complementary solvents such as A-MDEA, Purisol, Sulfinol and UCARSOL.

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[42] IEA Greenhouse Gas R&D Programme, *Carbon Dioxide Capture from Power Stations*.

[43] Ibid.

[44] North Dakota Gasification (a coal gasification plant) uses the Rectisol process.

Four methods are used commercially for regeneration of CO_2 in **carbon adsorption systems**. Pressure swing adsorption (PSA) lowers the pressure in the vessel containing the saturated bed (where the flue gas is directed and carbon dioxide is adsorbed) until trapped gases are pulled off the bed. Thermal swing adsorption utilises high temperature regeneration gas to drive off trapped gases. A third method employs a stream of fluid that attempts to wash the bed. A fourth method uses a gas stream that contains a material that can bump the trapped gas from its place in the bed. Most commercial carbon adsorption units utilise either PSA or a combined thermal swing/"wash" method. Carbon adsorption systems employ beds of alumina, zeolite or activated carbon. Other solid materials used commercially are alumina gel and silica gel.

Cryogenic systems involve a low temperature physical approach, in which the CO_2 is physically separated directly or by using a solvent. The CO_2 is usually condensed at cryogenic temperatures in these systems.

Two **membrane systems** to capture CO_2 are being developed, gas separation and gas absorption. Gas separation membranes are based on differences in the physical or chemical interaction between components in a gas mixture and the membrane material. These differences result in one component permeating faster through the membrane than another. The gas component dissolves into the membrane material and diffuses through it to the other side. Gas absorption membranes are used as contacting devices between a gas flow and a liquid flow. Separation results from the presence of an absorption liquid on one side of the membrane that selectively removes certain components from a gas stream on the other side of the membrane. Removal of CO_2 is achieved through the use of porous, hydrophobic membranes used in conjunction with suitable absorption liquids, such as sulphite, carbonate or amine solutions. Membranes use partial pressure as the driving force for separation and will therefore be most effective at high concentrations and pressure of CO_2.

12.4.2 Biomass-Fired Co-Generation

Biomass-fired co-generation is a technology that produces electricity from steam produced by a biomass-fired furnace. The key components to this technology are the biomass combustion chamber, a steam boiler, a steam turbine and electrical generator. Beyond the basic system, a fuel preparation and handling system (e.g. hogger, storage silos, conveyors) and environmental control systems (e.g. electrostatic precipitator) are required.

The electricity from this technology is considered to produce low indirect GHG emissions, since CO_2 from biomass combustion is not counted in GHG inventories. However, a small amount of methane and nitrous oxide are emitted from the combustion of biomass. The weighted average emission factor for these emissions is 2.6 tonnes of CO_2 equivalent per TJ of biomass - a contribution level which is about 5% that of natural gas. The marginal replacement of electricity purchased from utilities with biomass-fired co-generated electricity replaces 100% of the indirect GHG emissions from utility power generation with a very low amount of direct GHG emissions.

One key issue for biomass-fired cogeneration systems is the reliability of operation. A backup supply of electricity is usually required for an operation producing its own electricity. During regular grate cleaning or annual maintenance periods, electricity must be obtained from an alternate source. The demand charge for connection to a utility grid can be substantial.

12.4.3 Natural Gas-Based Power Generation

Natural gas-fired power generation is a technology that produces electricity from combustion gases or steam produced by burning natural gas fuel. Single-cycle gas turbines generate electricity directly and have electrical efficiencies ranging from 33-39%. Combined-cycle power plants use the same gas turbines and recover exhaust gas heat to produce steam in a heat recovery steam generator. Since this steam is used to drive a second electric generator, these systems tend to have electrical efficiencies over 50%. If some of the waste heat from the remaining low pressure steam can be recovered in a process heating use or a heating system, the overall system efficiency can increase to 80-85%.

Natural gas combined cycle power plants having 50% electrical efficiencies contribute GHG emissions at a rate of 100 tonnes CO_2/TJ. This technology can reduce indirect GHG emissions only in certain provinces where the marginal rate of GHG emissions from incremental power generation is higher than 100 tCO_2e/TJ. This is the case in 5 provinces (Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia).

A key design issue is whether the low-pressure steam generated can be utilised for heating applications. This can decrease the overall cost per terajoule of electricity.

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APPENDIX C:

Profile of Criteria Air Contaminants, Mercury and Greenhouse Gases Emissions in Alberta

March 2003

Submitted to:
Alberta Environment

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1. Executive Summary

1.1 Overview

This Appendix provides an analysis of emissions and ambient air quality for the major criteria (or common) air contaminants (CAC),[1] greenhouse gases (GHG) and mercury (Hg) in Alberta. On a quantitative basis, emissions of GHG are by far the largest. However, their effect on the environment and human health in Alberta is potentially quite different than CAC and mercury emissions. While GHG may contribute to global warming, CAC emissions result in acidifying deposition (acid rain), may contribute to ground level ozone formation and contribute to higher than desired levels of particulate matter that is inhaled. Mercury is considered a toxic substance to humans and the environment.

Table 1: Total Projected Alberta Emissions of GHG, CAC and Mercury

(tonnes)

Pollutant	2000	2005	2010	2020	Environmental Concern
Greenhouse gases	223,000,000	228,000,000	255,000,000	278,000,000	Global climate change#
Total* CAC	11,000	11,600	12,300	13,800	Acid rain deposition. Ground Level Ozone, Respirable/Inhalable PM
Mercury	1	1	1	1	Toxic substance

* Includes carbon monoxide and ammonia. # GHG emissions for 2005 to 2020 are MARKAL Base Case output for this study. Year 2000 emissions are from Environment Canada.[2] Mercury emissions between 0.8 and 1.1 tonnes per year and have been rounded to nearest tonne.

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[1] Common air contaminants include nitrogen oxides (NOx), sulphur oxides (SOx), volatile organic compounds (VOC), carbon monoxide (CO), total particulate (PM_T), particulate matter less than 10 microns PM_{10}, fine particulate matter less than 2.5 microns $PM_{2.5}$. Ammonia NH_3 emissions are also included in this study. Greenhouse gases include: carbon dioxide (CO_2 with global warming potential of 1.0); methane (CH_4 with GWP of 21), nitrous oxide (N_2O with GWP of 310), sulphur hexafluoride (SF_6 with GWP of 23,900), hydrofluorocarbons (HFCs with GWP between 140 and 11,000), perfluorocarbons (PFCs with GWP between 6,500 and 9,200). Often the GHGs are converted to equivalent global warming potential expressed as CO_2 (CO_2e).

[2] Environment Canada, *Canada's Greenhouse Gas Emissions: 1990 to 2000*, June 2002.

This analysis of CAC, GHG and mercury emissions in Alberta provides the pattern of historical emission sources and presents forecast estimates for the province to the year 2020. The sectoral pattern of year 2010 emissions is shown in the table below. A more detailed breakdown of Alberta's year 2000 GHG emissions inventory, as provided by Environment Canada, is included in this Appendix in the Section entitled, *Greenhouse Gas Emissions*.

Table 1: Estimated Alberta Emissions by Source, 2010

(Sectoral NOx, SOx, GHG, Hg, Emissions are Base Case MARKAL Output for Covered Sources Within Sectors)

	SOx (kt)	NOx (kt)	VOCs (kt)	PMT (kt)	PM10 (kt)	PM2.5 (kt)	Hg (tonne)	GHGs (Mt)
Total emissions	561	851	2,256	6,878	2,032	327		
Natural sources	-	29	1,297	54	46	38		
Anthropogenic emissions*	561	822	960	6,824	1,986	289	1	254
Covered Emissions from Sectors (NOx, SOx, GHG, Hg, Based on MARKAL Base Case)								
Electricity generation	129	98	1	9	8	8	0.94	58
Conventional oil & gas	229	372	497	2	2	2		51
Oil sands plants	169	157	280	32	18	11		57
Petroleum refineries	12	5	1	1	1	1		6
Chemicals		19	14	2	2	1		14
Cement	3	6	-	1		-		2
Pulp and paper	2	4	-	2	2	2		1
Wood Products	-	6						-
Total large industrial	545	667	793	49	2	2	0.94	189
Large industrial share**	97%	78%	35%	1%	2%	8%	94%	74%
Transportation	9	126	34	6	5	5		28
Buildings#	1	12	57	14	13	12		11
All other anthropogenic	6	18	76	6755	1935	247	<<1	27

Notes: kt = kilotonnes (1,000 tonnes), kg = kilogram, Mt = megatonnes (1,000,000 tonnes). GHG expressed as CO_2-equivalent.

** Approximate share of total emissions except for Hg and GHGs, which are shares of anthropogenic emissions.

# Buildings are residential, commercial and institution heating sources.

** "Anthropogenic emissions" and "All other anthropogenic" include PM (dust) emissions from vehicle traffic on paved and unpaved roads.

The scope of this analysis does not include an examination of the potential human health, environmental or global warming effects resulting from changes in emissions.

1.2 Criteria Air Contaminants (CAC)

CAC emissions result from anthropogenic (human activities) and natural sources (forest fires, biogenic sources such as trees and vegetation). The ratio of anthropogenic emissions to natural emissions varies by pollutant, as well as by season. Biogenic sources make large contributions to volatile organic compound (VOC) emissions, most of which occur during the growing seasons (spring/summer/fall). Similarly, forest fires can be significant sources of VOC, particulate matter (PM) and carbon monoxide (CO) emissions (forest fires would not be significant sources only during dry summers). However, natural sources represent a minor portion of SOx and NOx emissions. SOx and NOx emissions mostly result from anthropogenic activities. In Alberta, most emissions are a result of the combustion of fossil fuels (coal, natural gas and oils). Anthropogenic sources are also a major source of PM emissions, a large portion of which is road dust caused by vehicle traffic.

Particulate matter emissions from road dust are projected to increase by the greatest percentage (20% between 2000 and 2010). By contrast, SOx emissions, which have decreased since 1995, are projected to remain relatively flat by 2005 and increase slowly thereafter. NOx emissions are projected to grow in a similar pattern. SOx and NOx emissions will be influenced by lower transportation emissions resulting from improved fuel and vehicle emission standards, as well as the adoption of vehicle emission control technologies. VOC emissions are projected to grow slowly. A large portion of VOC emissions are from natural sources (i.e., forest fires, and biogenic sources), which are kept constant through the forecast period.

Table 2: Total Alberta CAC Emission Projections

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	4993	5749	6368	6878	7358	8079	11%	20%	41%
PM10	1530	1722	1889	2032	2168	2366	10%	18%	37%
PM2.5	261	281	304	327	352	383	8%	17%	36%
SOx	609	515	519	561	561	562	1%	9%	9%
NOx	715	771	783	851	891	907	1%	10%	18%
VOC	2051	2045	2098	2256	2296	2303	3%	10%	13%

Source: Cheminfo Services Inc.

Anthropogenic CAC emissions are projected to increase over time. The industrial, electricity power generation and the upstream oil and gas sectors are the major influences on SOx emissions, which declined between 1995 and 2000, are projected to increase between 2001 and 2020. However, these sectors will also contribute to increases in NOx emissions. Emission reductions are anticipated in the transportation sector. NOx emissions from transportation, which constituted 32% of total NOx emissions in Alberta in 1995, are expected to decline to the point of making up only 10% of NOx emissions by 2020.

Table 3: Emission Contributions from Major Source Categories

Projected 2010 CAC emissions. Changes since 2000 (kilotonnes)

Anthropogenic Sources: 2010	**PMT**	**PM10**	**PM2.5**	**SOX**	**NOX**	**VOC**
Industrial (includes electricity generation)	103	61	42	551	682	795
Residential, commercial, institutional	14	13	12	1	12	57
Transportation	6	5	5	9	126	38
Area sources[3] (e.g., road dust, solvents, agric. etc.)	6701	1906	230	0	2	69
Natural Sources	54	46	38	0	29	1297
Total 2010	6878	2032	327	561	851	2256
Total Percent Change vs. 2000	**PMT**	**PM10**	**PM2.5**	**SOX**	**NOX**	**VOC**
Industrial and electricity generation	**41%**	**42%**	**32%**	**10%**	**36%**	**41%**
Residential, commercial, institutional	**20%**	**19%**	**18%**	**-7%**	**-7%**	**22%**
Transportation	**-45%**	**-46%**	**-49%**	**-16%**	**-45%**	**-49%**
Area sources (e.g., road dust, solvents, agriculture, etc.)	**20%**	**18%**	**20%**	**13%**	**0%**	**14%**
Natural sources	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Total 2010	**20%**	**18%**	**17%**	**9%**	**10%**	**10%**

The largest projected increases are in emissions of particulate matter (PM), a large portion of which is from road dust caused by vehicle travel. PM emissions are projected to increase in conjunction with total distance travelled by all vehicles in Alberta. The total number of vehicles in Alberta is projected to increase from 1.7 million in 1995 to 2.3 million in 2010 and 2.7 million in 2020. The distance travelled by the total Alberta fleet is projected to increase by approximately 71% between 1995 and 2020. While PM vehicle-related emissions from road dust are projected to increase, fuel-related combustion emissions from on-road vehicles are projected to decrease as a result of the implementation of improved standards and reduced sulphur content in gasoline.

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[3] Area sources include road dust, and many other emissions (such as solvents use, cooking, and fuel distribution) that have not been included in the specific categories noted above (industrial, residential, commercial, institutional, or transportation).

Table 4: Total Alberta Anthropogenic CAC Emissions Projection

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	4938	5695	6314	6824	7304	8024	11%	20%	41%
PM10	1483	1676	1843	1986	2122	2319	10%	18%	38%
PM2.5	223	243	265	289	314	345	9%	19%	42%
SOx	609	515	519	561	561	562	1%	9%	9%
NOx	686	743	754	822	862	878	2%	11%	18%
VOC	754	748	801	960	1000	1006	7%	28%	35%

CAC emissions are expected to increase in some regions of Alberta much faster than others do. On the other hand, in some regions, some of the CAC are projected to actually decrease, in the absence of additional government influence. Emissions in the north-east portion of the province (defined by census regions #12 and #16) are anticipated to grow the fastest, since this area is the location of new oil sands development projects. NOx and VOC emissions in the region are projected to be substantially higher, assuming that the announced investments are made.

Changes in emissions in the urban areas around Calgary (census region #6) and Fort Saskatchewan/Edmonton (region #11) are much lower, and for some pollutants decreases in annual emissions are projected. For example, SOx and NOx emissions are projected to decline around Calgary between 2000 and 2020. Similarly, NOx emissions are expected to drop around Edmonton, and only minor increases in SOx emissions are expected. Declines in these regions are a result in lower emissions from transportation, electric power generation and processing of natural gas. Transportation emissions are being influenced by new fuel and vehicle emission standards.

1.3 Mercury Emissions

A total of approximately 0.8 tonnes of mercury were emitted to air by major point sources in Alberta in the year 2000. This total includes the facilities reporting to Environment Canada's National Pollutant Release Inventory (NPRI) program. Historical data are not provided, since it was not until the year 2000 that the NPRI mandatory reporting threshold for mercury releases/transfers was lowered to 5 kilograms per year (previously 10 tonnes/year of mercury manufacture, process or use). Outlined below are the mercury emissions reported to the NPRI from sources in Alberta.

Table 5: Year 2000 Mercury Emissions for Major Point Sources in Alberta

(kilograms)

Company Name	Facility Name	City	Air (Stack)	% of Total Emissions
TransAlta Corporation	Sundance Generation Plant	Duffield	283	35%
Edmonton Power (EPCOR)	Genesee Generating Station	Warburg	104	13%
TransAlta Corporation	Keephills Generating Plant	Duffield	102	13%
ATCO Electric	Battle River Generating Plant	Forestburg	102	13%
ATCO Electric	Sheerness Generating Station	Hanna	75	9%
TransAlta Corporation	Wabamun Generating Plant	Wabamun	54	7%
Syncrude Canada Ltd.	Mildred Lake Plant Site	Fort McMurray	27	3%
Sensor Environmental	Swan Hills Treatment Centre	Swan Hills	15	2%
Daishowa-Marubeni Intl.	Peace River Pulp Division	MD of Northern Lights	10	1%
AltaSteel Ltd.*	AltaSteel Ltd.	Edmonton	10	1%
Lafarge Canada Inc.	Exshaw Plant	Exshaw	7	1%
ATCO Electric	H.R.Milner Generating Station	Grande Cache	6	1%
Suncor Energy Inc.	Suncor Energy Inc. Oil Sands	Fort McMurray	5	1%
Imperial Oil	IOL Strathcona Refinery	Edmonton	1	<<1%
Petro-Canada	Edmonton Refinery	Edmonton	1	<<1%
Shell Canada Products	Shell Scotford Refinery	Fort Saskatchewan	1	<<1%
Total			**801**	100%

* Source: NPRI[4]. AltaSteel reported 0.03 kg of air emissions from storage, which is included in this total.
Source: National Pollutant Release Inventory. Rounded to nearest kilogram. Does not add to total due to rounding.

Estimates for natural sources of emissions of mercury are not available. However, it has been suggested that the principal sources of these emissions in Canada are soil, freshwater and marine surfaces, vegetation, and forest and bush fires. There is a large degree of uncertainty with respect to the percentage of total mercury releases represented by natural sources. However, most Canadian assessments have concluded that natural sources of mercury are a significant contributor to the overall global biogeochemical cycle and may account for up to half of the total mercury loading.[5]

Three companies operating six facilities account for close to 90% of the 0.8 tonnes of mercury emissions in the province. These six plants are the coal-fired electric generating facilities operated by ATCO Electric, Edmonton Power (EPCOR), and TransAlta

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[4] Environment Canada, *National Pollution Release Inventory (NPRI)*, Database http://www.ec.gc.ca/pdb/npri/npri_home_e.cfm

[5] Government of Canada, *Submission by Canada to UNEP Global Mercury Assessment*, September, 2001.

Utilities. Based on submissions to the NPRI, it is estimated that Canada's electric power generating power sector releases 34% of Canada's mercury emissions.[6]

A forecast of mercury emissions from the coal-fired electric generating sector in Alberta is provided below. Mercury emissions are projected to increase based upon an extrapolation of gigawatt-hours of electricity generated from coal.[7] All other minor sources of mercury have been projected to remain constant. Based on these simplifying assumptions, mercury emissions are projected to increase by a total of between 20 to 30% between 2000 and 2020.

Mercury primarily exists in two forms in flue gas, specifically in elemental and ionic forms. Some of the mercury is adhered to particulate matter contained in flue gases. Elemental mercury is more difficult to capture with existing emission control technologies than the ionic form of mercury, since is not very reactive and behalves like a gas at elevated temperatures, as those present in flue gas. The various coal types used by electric power plants (i.e., bituminous, sub-bituminous, lignite, anthracite) have different mercury emissions profiles, with respect to the release of elemental vs. ionic mercury. Six of the seven coal-fired electric power plants in Alberta use sub-bituminous coal, which results in high (i.e., 70 to 90%) elemental mercury emissions vs. ionic mercury emissions. Elemental mercury is less reactive than the ionic form, which results in greater local deposition of the ionic form, and long range transport of the elemental.

Table 6: Forecast of Mercury Emissions From Coal-Fired Power Plants and Other Sources in Alberta

Year	Coal Fired Power Plants (tonnes)	All Other Sources (tonnes)	Total Estimated Emissions (tonnes)
2000	0.7	0.1	0.8
2005	0.8	0.1	0.9
2010	0.9	0.1	1.0
2015	0.9	0.1	1.0
2020	0.9	0.1	1.0

Source: Cheminfo Services forecast estimates. Natural Resources Canada, *Canada's Emissions Outlook: An Update*, Dec. 1999. Year 2000 data from Environment Canada (National Pollutant Release Inventory- NPRI).

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[6] Lura Consulting, *Record of National Stakeholder Meeting Canadian Council of Ministers of the Environment, Mercury Canada-wide Standard for Electrical Power Generating Sector*, November 27, 2001.

[7] Coal based power generation in Alberta as contained in: Analysis & Modelling Group/Natural Resources Canada, *Canada's Emissions Outlook: An Update*, Dec. 1999. (with February/March 2002 revisions, which include new plants).

1.4 Greenhouse Gas Emissions

Environment Canada provides annual GHG emission estimates for Canada and for each of the provinces and territories.[8] Alberta accounted for approximately 31% of Canada's total GHG emissions in the year 2000. Emissions in Alberta have been forecast by the Analysis & Modelling Group (AMG) in collaboration with Natural Resources Canada working under the National Climate Change Process. AMG projects GHG emission in Alberta will reach approximately 264 megatonnes CO_2e by 2010. Most of the increases are associated with oil sands developments, electric power generation and transportation.

Table 7: Summary of GHG Emissions in Alberta

(Megatonnes CO_2e)

Source Category	1990	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 1990 to 2010	Change 2000 to 2020
Electric power generation	40	51	53	57	57	58	4%	12%	43%	14%
Total industrial	22	30	28	30	35	39	-7%	1%	38%	29%
Residential heating	7	8	7	6	6	6	-19%	-24%	-13%	-30%
Commercial/institutional	5	5	5	5	5	5	0%	0%	0%	0%
Fossil fuel industries	56	78	104	118	123	120	33%	51%	111%	54%
Transportation	23	31	27	28	29	32	-13%	-10%	22%	3%
Agricultural: soils, manure, livestock	17	19	18	19	19	20	-5%	0%	12%	5%
Waste, HFC, Miscellaneous	1	1	1	1	1	1	0%	0%	0%	0%
Total GHG Emissions	171	223	242	264	275	280	9%	19%	55%	26%
Canada Total	607	726	752	810	837	864	4%	12%	33%	19%

Source for 1990, 2000 emissions is Environment Canada.[9] http://www.ec.gc.ca/pdb/ghg/ghg_docs/2000nir_e.pdf..
Source for forecast emissions from 2005 to 2020 emissions, Analysis and Modelling Group/Natural Resources Canada, *Canada's Emissions Outlook: An Update, (CEOU)* Dec. 1999, HALOA Inc. MARKAL. Source for upward adjustments to CEOU (included in above forecast) from AMG/Natural Resources Canada, email correspondence to Cheminfo Services from AMG, Feb 26, 2002.

It should be noted that the actual year 2000 and forecast GHG emissions shown in the Table above will be close but not exactly match the results derived by MARKAL, and shown elsewhere is this Appendix. One reason for this is that MARKAL shows approximate midpoints (i.e., 2000, 2005, etc.) of 5-years spans. Minor calibration issues are also present, although these do not materially affect the MARKAL or other results and conclusions of this study.

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[8] Environment Canada, *Canada's Greenhouse Gas Emissions: 1990 to 2000*, June 2002.

[9] ibid

1.5 Summary Profile of Ambient Air Quality in Alberta

Alberta's annual average Ambient Air Quality Guideline (AAQG) concentrations for SOx and NOx are 11 parts by billion by volume (ppbv) and 32 ppbv, respectively. Hourly Ambient Air Quality Guideline concentrations for SOx and NOx are 172 ppbv and 212 ppbv, respectively. Alberta does not have standards for total hydrocarbons (THC) or VOCs.[10] However, Alberta does have standards for a number of individual hydrocarbons, such as acetaldehyde, acetic acid, acetone, benzene and others. Alberta's AAQG concentration for ozone is 82 ppbv for a 1-hour average.

Concentration data for numerous ambient air monitoring stations throughout Alberta show that all stations were more than 99.98% compliant with Alberta's AAQG for both SOx and NOx (100% for NOx) in terms of the number of hourly exceedances between 1995 and 2000. Annual averages from some monitoring stations in Edmonton and Calgary were close to the guideline value (i.e., within 6 ppbv for NOx). Annual averages of total hydrocarbon compounds (THC) concentrations from 20 monitoring stations in Alberta showed little variation from station to station.

Alberta Environment is operating in a "keeping clean areas clean" context, which is a reasonable approach given achievement of ambient air quality guidelines. The reasonableness of this approach is also borne out by the small projected increases in SOx and NOx. However, Alberta Environment recognizes that emission increases in some regions may result in increased pressures on air quality. These pressures will come about as a result of an increasing population, new oil sands plants, increased numbers of vehicles and the general effects of an expanding economy. While improved vehicle emission standards, adoption of some control technologies among industrial facilities, as well as actions on climate change should also have a positive effect, emissions are projected to increase. Despite the generally positive picture, there are reasons why ongoing management and strategic actions on some pollutants and GHG will be required over time, such as:

- Alberta Government, federal government, other provinces and territories are committed to action on climate change;
- as scientific understanding increases, guidelines are revised, generally in a stricter direction; and
- local effects, particularly in regions of very high economic and emissions growth (e.g., in the northeast part of province) can be a concern for people in the region and neighbouring populations.

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[10] Few jurisdictions have ambient air quality guidelines for total VOC concentrations.

Emissions trading provides a management option that Alberta Environment is considering. Emissions trading regimes have the potential to achieve desired emission reductions and related air quality objectives in an economically optimal manner - that is at least-cost to society.

1.5.1 External Influences on Alberta Air Quality

An analysis of Alberta's major NOx and SOx emission sources (i.e., industrial, EPG and transportation) found the province's internal sources are much greater than any other's single state's or province's emissions from comparable sources. Alberta emissions of SOx and NOx are approximately double the emissions from surrounding American states. However, Alberta's emissions are approximately equal to the total of the emissions from the surrounding states and BC. Alberta's VOC emissions from industrial and transportation sources (there are negligible amounts of VOC from the electric power generating sector) greatly exceed the VOC emissions from the surrounding states and BC. Alberta's emissions are at least 3 times greater than the sum of the surrounding states, as well as approximately 3 times greater than BC's and SK's VOC emissions.

Table 8: Comparison of Industrial, Electric Power Generation and Transportation CAC Emissions Between Alberta and Surrounding Regions, 1999[11]

(Estimated 1999 Emissions for Alberta, BC and SK - kilotonnes)

Region	PM10	PM2.5	NOx	SOx	VOC	CO
Alberta	54	42	721	515	638	1162
Surrounding States (AK, WA, OR, ID, MT)	73	48	354	232	165	2210
BC	104	81	320	174	180	1301
SK	57	22	210	138	175	471
Ratio of Surrounding Regions' Emissions to Alberta Emissions						
Surrounding States	134%	115%	49%	45%	26%	190%
BC	192%	192%	44%	34%	28%	112%
States plus BC	325%	307%	93%	79%	54%	302%
SK	105%	53%	29%	27%	27%	40%

Source: US EPA[12]. Environment Canada, based on forecast of 1999 emissions.[13]

One major factor that contributes to Alberta's larger emissions is the Upstream Oil & Gas sector, which includes the existing oils sands mining and bitumen upgraders. BC, SK as well as the surrounding states also have conventional oil and gas sector production activities. However, the size of the sectors in surrounding regions is much smaller than the sector in Alberta. Oils sands and bitumen upgraders are not present in BC or surrounding states. The other major factor that contributes to Alberta's SOx and NOx emissions being larger than those in the surrounding regions is the use greater use of coal for electricity generation. BC has no coal-based electricity generation. It relies on hydropower and a minor amount of electricity generated with natural gas.

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[11] Only 1999 inventory data available from US EPA.

[12] US EPA, National Emission Inventory Data, Criteria Inventory 1999, http://www.epa.gov/ttn/chief/net/index.html

[13] Environment Canada, Pollution Data Branch, *Development of the NAICC Base Case Consensus Forecast of Common Air Contaminants 1995 – 2020*, March 2002.

Given that, in general, Alberta's emissions are greater than those of the surrounding regions, it can be concluded that the emission sources within the province will have the greatest effect on local ambient air quality. The exact quantitative effect of transboundary pollutant transfers from other regions entering Alberta is unknown and would require complex air quality modelling to determine. However, it can be concluded that transboundary emissions will likely have a minor effect on Alberta air quality that for most, if not all, regions in Alberta will be a very small fraction of the effect of local emission sources within the province. The reason for this is, in part, that only a fraction of the emissions from other regions enter Alberta.

Alberta Environment has studied the transboundary transport of SOx and NOx in Alberta (Cheng, Angle).[14] Based on ambient air quality modelling of emissions in Alberta and surrounding regions, it was concluded that approximately 10% of sulphur in the province was transported from British Columbia. Similarly, British Columbia represented 18% of the total sources of NOx entering Alberta air space. Given that the prevailing winds through Alberta are from the west, the study concluded that the majority of Alberta emissions are transported into Saskatchewan, while some of the rest travel to Northwest Territories, Manitoba and the United States. The study did not consider transboundary influence of U.S. emissions into Alberta.

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[14] Cheng, L., Angle, R.P., *Model-Calculated Interannual Variability of Concentration, Deposition and Transboundary Transport of Anthropogenic Sulphur and Nitrogen in Alberta,*

2. Introduction

2.1 Scope

This analysis profiles emissions and ambient air quality for Alberta's criteria (or common) air contaminant (CAC), mercury (Hg) and greenhouse gas (GHG) emissions.[15] The analysis includes historical emission estimates (e.g., 1995, 2000), but focuses on future emissions to the year 2020. The analysis is presented using the following categorization of emission sources:

Anthropogenic Sources
- industrial (including electric power generation);
- residential, commercial, and institutional;
- transportation;
- area sources - non-energy (e.g., road dust, construction, prescribed burning, solvents use, agriculture, etc.);

Natural Sources
- forest fires; and
- biogenic sources.

The analysis concentrates on specific CAC emissions covered in the scope of the Major Feasibility Study (namely PM, NOx, SOx, VOC and mercury (Hg). GHGs are also covered, since they are also encompassed by the scope of potential emission trading systems to be considered in the Major Feasibility Study. Much of the analysis of CAC emissions contained in this Appendix is based on Cheminfo's recent forecast of CAC emissions in Alberta. An emissions inventory for mercury has been prepared using available data, literature and reference sources. Current and projected estimates of GHG emissions are based on the forecast prepared in 1999 by the Analysis and Modelling Group (AMG) of the National Climate Change Process (prepared in collaboration with Natural Resources Canada).[16] Revisions to the GHG forecast that were prepared by the AMG in March 2002 have been incorporated in the emissions analysis.

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[15] Common air contaminants include nitrogen oxides (NOx), sulphur oxides (SOx), volatile organic compounds (VOC), carbon monoxide (CO), total particulate (PM_T), particulate matter less than 10 microns PM_{10}, fine particulate matter less than 2.5 microns $PM_{2.5}$. Ammonia NH_3 emissions are also included in this study. Greenhouse gases include: carbon dioxide (CO_2 with global warming potential of 1.0); methane (CH_4 with GWP of 21), nitrous oxide (N_2O with GWP of 310), sulphur hexafluoride (SF_6 with GWP of 23,900), hydrofluorocarbons (HFCs with GWP between 140 and 11,000), perfluorocarbons (PFCs with GWP between 6,500 and 9,200). Often the GHGs are converted to equivalent global warming potential expressed as CO_2 (CO_2e).

[16] Analysis & Modelling Group/Natural Resources Canada, *Canada's Emissions Outlook: An Update*, December 1999.

This Appendix also characterizes air quality in Alberta, based on available monitoring data for the contaminants of interest. Tabulation of monitoring data, including information on the three critical airsheds (areas around Calgary, Edmonton and north-east portion of the province around tar sands projects), is presented.

2.2 Purpose of This Analysis

The purpose of presenting the emission profiles and the ambient air quality analysis is to provide perspective regarding the current (year 2000) air quality in Alberta in context of the current (year 2000) emissions and to assess the potential implications and related issues of increased emissions over time for the air quality. The analysis provides one source of information among other sources and approaches that can be applied to infer potential emission reductions required to maintain air quality standards and objectives.

The analysis also provides a point of reference for historical trends and future emissions. This provides valuable perspective in context of the assessment of emissions trading and the costs of achieving emission reductions.

3. Criteria Air Contaminants

3.1 Introduction

The ratio between anthropogenic and natural CAC emissions varies significantly by contaminant. Fossil fuel use for heat and electricity generation (i.e., energy-related) and mere combustion (where derived heat is not utilized or electricity is not made from the burning of fossil fuels) are prominent sources of nitrogen oxides (NOx), sulphur oxides (SOx) emissions, and carbon monoxide (CO) emissions.[17] In the case of total particulate (PM_T) and PM_{10} (i.e., particulate matter less than 10 microns) anthropogenic non-energy area sources dominate since they include dust from paved and unpaved roads resulting from vehicle traffic. Natural sources such as forest fires and biogenic sources[18] are major contributors to total volatile organic compound (VOC) emissions.

The main focus of this analysis is on anthropogenic emissions from industrial sources in Alberta. Large natural sources are documented and included in the total emissions, but in the forecast period to 2020, these are kept constant at 1995 levels. These sources are highly variable from year to year such that any analysis regarding how they may change due to natural causes (e.g., lightning for forest fires, precipitation, temperatures, etc.) requires further detailed research and customized modelling beyond the scope of this project. The inclusion of natural sources provides perspective on the relative contribution to total CAC air emissions and can be useful for regional ambient air quality modelling using the results of this analysis.

The starting point for this forecast is the 1995 inventory of CAC emissions in Alberta, which is the most comprehensive up-to-date inventory of CAC emissions. The 1995 inventory has been prepared by Alberta Environment in collaboration with Environment Canada[19]. While year 2000 emissions (mostly SOx and NOx emissions) were available for major industrial facilities, a complete inventory of all pollutants and sources for the year 2000 emissions is not currently available for Alberta. Therefore, the year 2000 estimates in this study should in most cases be considered a part of the projection period.

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[17] Primary sources only. Secondary formation not included in this forecast.

[18] Biogenic sources are largely related to vegetation and animal sources (non-agricultural).

[19] Environment Canada, *1995 Criteria Air Contaminant Emissions for Canada*, December 1998.

Table 9: Estimates of Total 2000 Alberta CAC Emissions

(kilotonnes)

Anthropogenic Sources	**PMT**	**PM10**	**PM2.5**	**SOX**	**NOX**	**VOC**
Industrial (includes electricity generation)	73	43	32	503	500	564
Residential, commercial, institutional	11	11	11	1	13	47
Transportation	10	10	9	11	227	76
Area sources[20] (e.g., road dust, solvents, agric. etc.)	5600	1612	191	0	2	61
Natural Sources	54	46	38	0	29	1297
Total 2000	5749	1722	281	515	771	2045
Portion of Total	**PMT**	**PM10**	**PM2.5**	**SOX**	**NOX**	**VOC**
Industrial and electricity generation	1%	2%	11%	98%	65%	28%
Residential, commercial, institutional	0%	1%	4%	0%	2%	2%
Transportation	0%	1%	3%	2%	29%	4%
Area sources (e.g., road dust, solvents, agriculture, etc.)	97%	94%	68%	0%	0%	3%
Natural sources	1%	3%	14%	0%	4%	63%

Source: Alberta Environment. Cheminfo Services Inc.

This forecast of CAC emissions is established in context of Canada's economic and energy outlook as developed by the Analysis and Modelling Group (AMG) of the National Air Issues Co-ordinating Committee on Climate Change (NAICC-CC). The AMG is made up of provincial (including Alberta), territorial and federal government representatives, including Natural Resources Canada. The AMG, in collaboration with Natural Resources Canada developed a consolidated economic and energy analysis to support analysis for the National Climate Change Process. The economic and energy analysis was published in the report on greenhouse gas (GHG) emissions entitled, *Canada's Emissions Outlook: An Update*, in December 1999 (hereafter referred to as CEOU).[21] The analysis excludes the potential effects of climate change or other potential government policies on greenhouse gas and CAC emissions. The AMG provided some modifications (February/March 2002) to that forecast. This CAC emissions forecast incorporates those adjustments, especially as they relate to the electric power generation sector in Alberta. While the CEOU provides a foundation for this Appendix, substantial additional industry input was incorporated in this forecast to take into consideration emission reduction controls and other effects that relate to future CAC emissions.

3.2 CAC Emissions Growth

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[20] Area sources include road dust, and many other emissions (such as solvents use, cooking, and fuel distribution) that have not been included in the specific categories noted above (industrial, residential, commercial, institutional, or transportation).

[21] AMG/Natural Resources Canada, *Canada's Emissions Outlook: An Update*, December 1999. www.nccp.ca

Overall CAC emissions in Alberta are projected to increase under business-as-usual (BAU) conditions. BAU conditions include continued economic growth as reflected by changes in Alberta's total Gross Domestic Product (GDP), which is projected to increase 24% between 2000 and 2010, and 56% between 2000 and 2020 (AMG 1999)[22]. The total energy consumption by the Alberta economy is projected to increase at a slower pace, largely as a result of improvements in energy efficiency. Total energy consumption in Alberta was projected to increase by 20% between 2000 and 2020 by the Analysis and Modelling Group, although this has been revised upward to reflect increased oil sands developments and electric power generation.

Total CAC emissions[23] are projected to increase 18% by 2010 and 32% by 2020 over 1995 levels. These slower growth rates (versus economic growth) result from anticipated energy efficiency improvements, a general shift to less CAC-intensive fuels such as natural gas (in some sectors) and a constant level of future emissions assumed for natural and some agricultural sources. In addition, reduced emissions from transportation are anticipated in context of improved vehicle emission standards and regulated reductions in the sulphur content of gasoline and on-road diesel. In absence of the improved energy efficiency and fuel switching throughout the economy, CAC emissions would be projected to increase at a much faster rate.

Table 10: Macroeconomic Assumptions, Energy and Environmental Performance Context for Alberta

Parameter	**1995**	**2000**	**2010**	**2020**
Alberta GDP ($ billion 1986) (CEOU)	$73	$85	$106	$133
Total energy consumed (000s PJ)	1.4	1.5	1.7	1.8
Total CAC emissions (000' kilotonnes)	10.5	11.0	12.3	13.8
Total GHG emissions (000' kilotonnes, megatonnes)	200	223	264	280
Performance Indicators				
Energy (PJ/GDP)*	19	18	16	14
Total CAC Emissions (kilotonne-CAC/$billion-GDP)	144	130	116	104
GHG Emissions (megatonnes-GHG/$billion-GDP)	2.7	2.6	2.5	2.1

* CAC emissions calculated in this study. Total includes carbon monoxide and ammonia. CEOU economic data.
* PJ is petajoules. Actual GHG emissions for 1995, 2000. CEOU forecasts for 2010, 2020. GDP data from CEOU

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[22] AMG/Natural Resources Canada, *Canada's Emissions Outlook: An Update*, December 1999. Constant 1986$. This estimate may indeed now be higher in context of additional announced oil sands projects (the effects of which are reflected in the CAC emissions forecast.)

[23] Total CAC emissions are the sum of PM_T, SOx, NOx, CO, VOC and NH_3.

The magnitude of projected change for each of the CAC contaminants is quite different. Total particulate emissions (PM_T) and PM_{10}, a large portion of which are from road dust, are projected to increase by the greatest percentage. By contrast, SOx and CO emissions are projected to actually decrease, largely because of lower transportation emissions due to improved fuel and vehicle emission standards, as well as the adoption of SOx control technologies. VOC emissions are projected to grow slowly. A large portion of VOC emissions are from natural sources (i.e., forest fires, and biogenic sources), which are kept constant through the forecast period.

Table 11: Total Alberta CAC Emission Projections

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	4993	5749	6368	6878	7358	8079	11%	20%	41%
PM10	1530	1722	1889	2032	2168	2366	10%	18%	37%
PM2.5	261	281	304	327	352	383	8%	17%	36%
SOx	609	515	519	561	561	562	1%	9%	9%
NOx	715	771	783	851	891	907	1%	10%	18%
VOC	2051	2045	2098	2256	2296	2303	3%	10%	13%

Source: Cheminfo Services Inc.

Anthropogenic CAC emissions are projected to increase over time. The industrial sectors (including electricity) and the Upstream Oil and Gas in particular are the major influences on SOx emissions, which declined from 1995 to 2000, but which are projected to increase between 2001 and 2020. These sectors will also contribute to increases in NOx emissions. Emission reductions are anticipated in transportation sector. NOx emissions from transportation, which constituted 32% of total NOx emissions in Alberta in 1995, are expected to decline to the point of making up only 10% of NOx emissions by 2020.

Table 12: Projected 2010 CAC Emissions (Changes Since 2000)

(kilotonnes)

2010 Anthropogenic Sources	**PMT**	**PM10**	**PM2.5**	**SOX**	**NOX**	**VOC**
Industrial (includes electricity generation)	103	61	42	551	682	795
Residential, commercial, institutional	14	13	12	1	12	57
Transportation	6	5	5	9	126	38
Area sources[24] (e.g., road dust, solvents, agric. etc.)	6701	1906	230	0	2	69
Natural Sources	54	46	38	0	29	1297
Total 2010	6878	2032	327	561	851	2256
Total Percent Change vs. 2000	**PMT**	**PM10**	**PM2.5**	**SOX**	**NOX**	**VOC**
Industrial and electricity generation	**41%**	**42%**	**32%**	**10%**	**36%**	**41%**
Residential, commercial, institutional	**20%**	**19%**	**18%**	**-7%**	**-7%**	**22%**
Transportation	**-45%**	**-46%**	**-49%**	**-16%**	**-45%**	**-49%**
Area sources (e.g., road dust, solvents, agriculture, etc.)	**20%**	**18%**	**20%**	**13%**	**0%**	**14%**
Natural sources	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Total 2010	**20%**	**18%**	**17%**	**9%**	**10%**	**10%**

Source: Cheminfo Services Inc.

The largest projected increases are in emissions of particulate matter (PM), a large portion of which is from road dust caused by vehicle travel. PM emissions are projected to increase in conjunction with total distance travelled by all vehicles in Alberta. The total number of vehicles in Alberta are projected to increase from 1.7 million in 1995 to 2.3 million in 2010 and 2.7 million in 2020 (CEOU). The total distance travelled by the entire Alberta fleet is projected to increase by approximately 71% between 1995 and 2020. While PM vehicle-related emissions from road dust are projected to increase, fuel-related combustion emissions (e.g., SOx, NOx, CO, VOC, PM) from on-road vehicles are projected to decrease as a result of the implementation of improved standards and reduced sulphur content in gasoline. Total emissions of these pollutants as well as emissions per vehicle are projected to decline. Improvements in transportation emissions make an important contribution to the projection for reduced emissions of CO, which by 2010 is projected to be 30% lower than 1995.

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[24] Area sources include road dust, and many other emissions (such as solvents use, cooking, and fuel distribution) that have not been included in the specific categories noted above (industrial, residential, commercial, institutional, or transportation).

Table 13: Total Alberta Anthropogenic CAC Emissions Projection

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	4938	5695	6314	6824	7304	8024	11%	20%	41%
PM10	1483	1676	1843	1986	2122	2319	10%	18%	38%
PM2.5	223	243	265	289	314	345	9%	19%	42%
SOx	609	515	519	561	561	562	1%	9%	9%
NOx	686	743	754	822	862	878	2%	11%	18%
VOC	754	748	801	960	1000	1006	7%	28%	35%

3.3 Regional CAC Emissions Forecast Summary

Estimates of forecasted 2010 emissions from each source category and for each CAC were developed for each of Alberta's 19 census divisions (or regions). In general, the methodology applied to estimate regional emissions combined previous 1995 regional estimates for area sources and incorporated the 2010 emission contributions from major facility point sources (i.e., mostly electric power plants and new oil sands projects) in the specific regions in which they are located.

The census regions surrounding and encompassing Calgary and Edmonton contain the largest sources of most of the pollutants. The oil sands region in the northeast portion of the province is also a significant region of emissions. Residential fuel burning, transportation and agriculture are examples of large sources located in these areas. Upstream oil and gas operations and other manufacturing sources also contribute a significant amount to these regions. Forest fires are an important source in northern Alberta regions as are anticipated new oil sands projects. Descriptions of these and two other regions that represent the majority of emissions for some of the pollutants are provided below, as well as examples of the major sources within those regions.

Table 14: Regions Contributing Major Proportions of Emissions in Alberta

Census Region	Description of Region	Major Sources Within Region
6	Area surrounding Calgary	General concentration of industry, electric power generation, agriculture, transportation and residential, oil & gas operations
11	Area surrounding Edmonton	General concentration of industry, electric power generation, agriculture, transportation and residential, oil & gas operations
16, 12	Northeast Alberta, including Wood Buffalo national park	Oil sands projects, forest fires

Source: Cheminfo Services Inc.

The following table presents the year 2010 CAC emissions for each of the 19 census regions for each contaminant. Additional detailed tables showing the regional emissions for each sector and source category are included in the Appendix A. A map of the census regions is shown below.

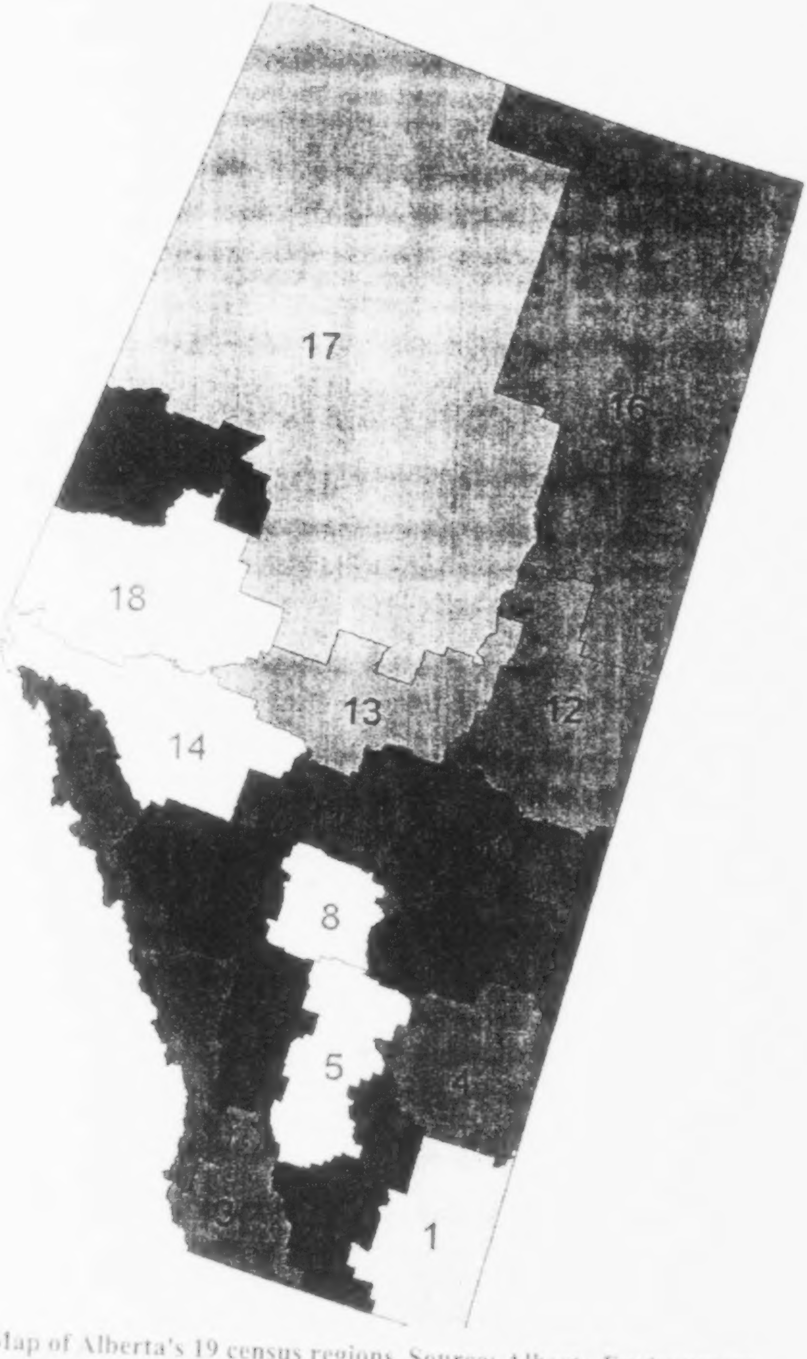
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Figure 1: Map of Alberta's 19 census regions. Source: Alberta Environment

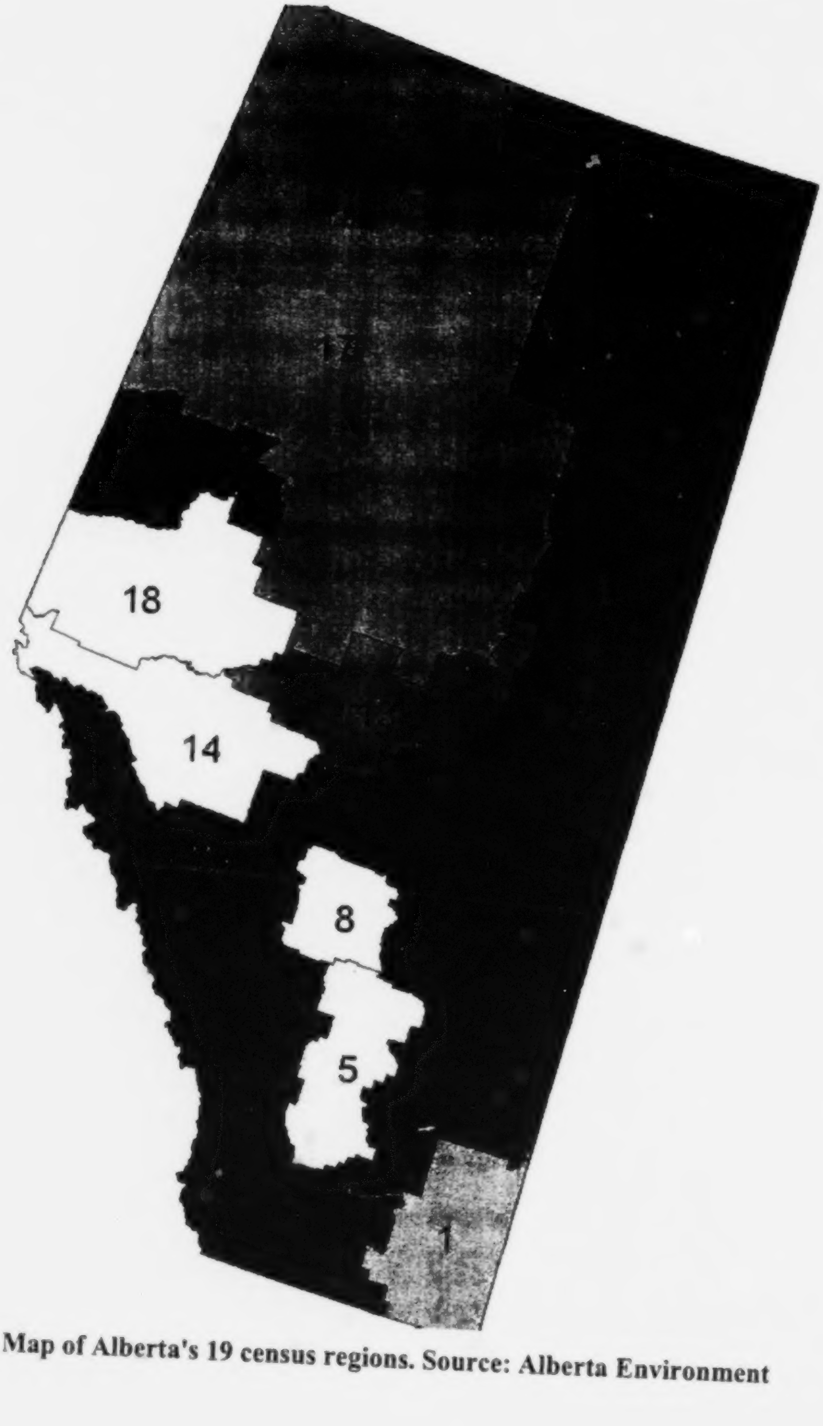

Figure 1: Map of Alberta's 19 census regions. Source: Alberta Environment

Table 15: 2010 CAC Emissions Contributions from 19 Alberta Census Regions

(% Of Total Anthropogenic Emissions Only)

	PM_T	PM_{10}	$PM_{2.5}$	SO_x	NO_x	VOC
Total Anthropogenic Emissions (kilotonne)	6878	2032	327	561	836	1021
Major Regions						
6: Calgary area	**9%**	**8%**	**5%**	**11%**	**9%**	**22%**
11: Edmonton, Fort Saskatchewan	**10%**	**10%**	**8%**	**18%**	**19%**	**13%**
12: Oil Sands Region	**5%**	**5%**	**5%**	**2%**	**4%**	**2%**
16: Oil Sands Region	**2%**	**3%**	**10%**	**27%**	**20%**	**34%**
14: West of Edmonton	**30%**	**29%**	**28%**	**3%**	**3%**	**2%**
Other Regions						
1	3%	3%	3%	0%	4%	3%
2	4%	4%	3%	5%	4%	2%
3	2%	2%	1%	2%	2%	1%
4	5%	5%	4%	7%	4%	0%
5	3%	3%	2%	1%	3%	1%
7	4%	4%	4%	4%	3%	2%
8	3%	3%	2%	2%	4%	4%
9	1%	1%	1%	4%	2%	1%
10	7%	7%	6%	1%	3%	2%
13	3%	3%	3%	5%	3%	2%
15	1%	1%	1%	2%	1%	1%
17	4%	5%	11%	2%	6%	5%
18	1%	1%	1%	3%	3%	1%
19	3%	3%	3%	1%	2%	2%

Source. Cheminfo Services Inc. May not add to 100% due to rounding.

3.4 CAC Emissions From Industrial and Electric Power Generation Sectors

Industrial sectors (including electric power generation) encompass a great variety of processes and equipment that generate CAC emissions in the production of products and delivery of services, including electricity. Combustion of sulphur containing fuels and UN-recovered sulphur from upstream oil and gas operations are the major sources of SOx emissions in Alberta. NOx emissions are practically all fuel combustion-related. PM emissions include many process emissions as well as fuel combustion sources. Industrial sources are a relatively minor portion (i.e., 7%) of total estimated ammonia emissions in Alberta.

Table 16: Total Alberta Industrial CAC Emissions Projection

(Kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	84	73	86	103	113	117	18%	41%	60%
PM10	48	43	49	61	66	68	14%	42%	58%
PM2.5	35	32	35	42	47	48	9%	32%	52%
SOx	601	503	508	551	551	551	1%	10%	10%
NOx	444	500	574	682	746	769	15%	36%	54%
VOC	554	564	634	795	828	818	12%	41%	45%

Includes Electric Power Generation.

The projected growth in emissions varies by contaminant. NOx emissions are projected to grow the most by 2020 as a result of increased use of fossil fuels. SOx emissions are projected to decline in the short term largely as a result of the reduction at upstream oil and gas operations, and then increase moderately.

Four industrial sectors and the electric power generation sector account for the great majority of emissions as well as energy consumption in the province. These are.

- Upstream oil and gas;
- Electric power generation;
- Petroleum refining;
- Cement; and
- Chemicals.

The five sectors account for over 90% of total SOx, NOx and VOC industrial emissions in Alberta as shown in the table below. However, for PM, NOx, and VOC the contribution from these 5 sectors to total Alberta emissions (all natural and anthropogenic sources) is much lower. SOx emissions are largely derived from these 5 sectors.

Table 17: Estimated Emissions Contribution from 5 Major Sectors

(Based on Year 1995 Emissions - Not Substantially Different in Future Years)

Contaminant	Portion of Total Industrial Emissions	Portion of Total Alberta Emissions from all sources*
PMT	27%	0.4%
PM10	35%	1%
PM2.5	42%	5%
SOx	98%	81%
NOx	95%	66%
VOC	100%	27%

* Natural and anthropogenic sources.

The table below shows the year 2010 projected emissions for each sector and the contribution to total industrial plus electric power generation sector emissions.

Table 18: Year 2010 Projected Industrial and EPG Emissions by Sector

(Tonnes)

Sector	PMT	PM10	PM2.5	SOx	NOx	VOC
Upstream Oil & Gas	33417	19823	12263	391996	505905	777095
Electric Power Generation	8989	8067	7637	131348	113174	1453
Cement	1149	388	118	2058	4836	40
Chemical	1831	1746	741	2979	29077	13690
Mining, Quarrying	9856	5456	4042	3479	2526	814
Iron & Steel	267	225	86	17	230	2
Non-Ferrous Metals	16	15	13	4181	465	2
Petroleum Refining	1069	1068	1067	11987	4757	793
Pulp & Paper	2482	2258	2160	2814	4758	62
Other Manufacturing	44185	21944	13938	228	16230	582
Total industrial	**103262**	**60990**	**42064**	**551086**	**681958**	**794533**
	PMT	**PM10**	**PM2.5**	**SOx**	**NOx**	**VOC**
Upstream Oil & Gas	32.4%	32.5%	29.2%	71.1%	74.2%	97.8%
Electricity	8.7%	13.2%	18.2%	23.8%	16.6%	0.2%
Cement	1.1%	0.6%	0.3%	0.4%	0.7%	0.0%
Chemical	1.8%	2.9%	1.8%	0.5%	4.3%	1.7%
Mining, Quarrying	9.5%	8.9%	9.6%	0.6%	0.4%	0.1%
Iron & Steel	0.3%	0.4%	0.2%	0.0%	0.0%	0.0%
Non-Ferrous Metals	0.02%	0.02%	0.0%	0.8%	0.1%	0.0%
Petroleum Refining	1.0%	1.8%	2.5%	2.2%	0.7%	0.1%
Pulp & Paper	2.4%	3.7%	5.1%	0.5%	0.7%	0.0%
Other Manufacturing	42.8%	36.0%	33.1%	0.0%	2.4%	0.1%

Note: Individual tonne and percentage figures in the above table may not add up exactly to totals shown due to rounding.

3.5 Electric Power Generation

Alberta's electric power generation is poised to grow to meet the requirements of a growing provincial economy. There have been public announcements of major new power generating facilities. New facilities based on using coal as well as natural gas are anticipated. Additional capacity (beyond that which has been announced) has been assumed in this analysis. Power generation capacity is projected to increase by approximately 40% between 2000 and 2010. Industry sources from the electric power generation sector contacted in this study also indicate that some of the smaller, older units are likely to close by 2010 or soon thereafter. At some other units incremental capacity expansions are expected. The major power generation expansions include:

- Fording's coal based facility in Brooks (2006, 2007);
- TransAlta's coal based facility in Keephills (2007, 2008);
- AES Calgary's natural gas combined cycle (NGCC) based facility near Calgary (2005); and
- EPCOR's coal based facility in Genesee (2005).

Table 19: Capacities and Expansions of Major Electric Power Generating Companies in Alberta

(megawatts)

Company	Location	2000	2010	2020
TransAlta (existing)	Wabamun, Sundance, Keephills	3520	3086	3086
TransAlta (expansion)	Keephills	0	900	900
Edmonton Power (EPCOR) (existing)	Genesee	1480	1480	1480
Edmonton Power (EPCOR) (expansion)	Genesee	0	500	500
TransAlta/ATCO Electric	Sheerness	800	800	800
ATCO Electric	Battle River	675	675	675
Fording	Brooks	0	1000	1000
AES Calgary	Calgary	0	500	500

3.5.1 Emission Trends

Alberta's electric power generating sector is a major source of SOx and NOx emissions, accounting for approximately 20% of total provincial SOx and 13% of NOx emissions. By comparison, the sector's portion of other CAC emissions is less than 3% of provincial totals. Practically all of the SOx emissions are from the coal-fired power plants. These plants also account for 80% to 90% of NOx emissions from the sector.

Table 20: Forecast of Emissions from Electric Power Generation

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	10	9	9	9	9	9	3%	-2%	-2%
PM10	9	7	7	8	8	8	-14%	-4%	-5%
PM2.5	9	6	7	8	8	8	-19%	-8%	-8%
SOx	130	125	129	131	131	131	3%	5%	5%
NOx	91	94	102	113	115	117	8%	20%	23%
VOC	1	1	1	1	1	1	13%	33%	36%

Note: Excludes emissions from power generation at oil sands developments. VOC emissions are rounded to nearest kilotonne. VOC percentage changes reflect growth in emissions based on greater significant digits than shown.

Although power generation capacity and production are forecast to grow during this decade, emissions are not expected to match this growth. New power generating plants will be complying with new provincial emission performance standards. Alberta's new standards for power facilities came into effect in mid-2001. The impact of these emission standards will be to control the majority of additional potential PM, PM_{10}, $PM_{2.5}$, and SOx emissions, as well as a portion of potential NOx emissions from new coal-fired generating plants. Most natural gas based facilities would be in compliance with the new standards for all CACs. For example, one natural gas combined cycle (NGCC) system in Alberta, which features continuous emissions monitoring, operates with a NOx emissions rate of 50 to 80 nanograms/joule-in (ng/J-in). It has been assumed that new NGCC generating stations will operate close to 80 ng/joule-in. The new emission performance standards combined with the closure of some older emissions-intensive facilities should result in lower PM_T, PM_{10}, $PM_{2.5}$ and very little growth in SOx emissions.

Table 21: Emission Performance Standards for Electric Power Generating Facilities in Alberta

(nanograms/joule-in - ng/J)

	Average Alberta Coal-Fired Facility*	Existing (New) Alberta Standards	Potential Technology Implication or Equivalent
PM_T	20	13	Baghouses
NOx	164	125	Selective Non-Catalytic Reduction (SNCR) and Low-NOx burners
SOx	270	180	Wet scrubbing

* Based on 1995 consumption of coal for power generation and related estimated emissions.

In some cases, new facilities will have emission rates that are even lower than the new performance standards. For example, EPCOR's expansion at Genessee will feature SOx levels between 75 and 80 ng/joule-in. Similarly, TransAlta's expansion at Keephills will feature SOx emissions lower than the standard. Another factor that will dampen the growth for NOx emissions is increased market penetration of natural gas combined cycle (NGCC) facilities that operate with lower NOx emission rates per unit of power generated than existing facilities (and have negligible SOx emissions).

SOx emissions are projected to increase slowly from year 2000 levels. The power generation share of natural gas is expected to increase and older, coal-based units with higher sulphur emissions per unit of power generated are likely to be shut down. Any new coal-fired units are likely to feature higher efficiency and lower SOx emissions per unit of power generated. No new coal facilities have been assumed in period 2010 to 2020. It has been assumed that all of the increase in power generating capacity is fuelled by natural gas.

3.6 Upstream Oil and Gas

The upstream oil and gas industry is a large, vital and growing component of Alberta's economic landscape. While the industry is projected to continue to increase its production, the rate of growth of CAC emissions will not match that growth. However, most CAC emissions will continue to rise and will be significantly greater than 2000 levels by 2020. The exception is SOx emissions, which will increase from year 2000 levels, but are projected to be 11% to 12% lower than 1995 levels by 2010 and 2020.

Table 22: Forecast of Total Emissions from Upstream Oil and Gas Industry

(includes oil sands, bitumen upgraders, upstream oil & gas facilities)
(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	6	7	19	33	39	40	162%	365%	452%
PM10	4	4	10	20	22	23	151%	382%	449%
PM2.5	3	3	7	12	15	16	112%	264%	363%
SOx	440	354	355	392	390	389	0%	11%	10%
NOx	298	346	413	506	564	580	19%	46%	68%
VOC	541	548	617	777	810	799	13%	42%	46%

For this forecast, different emission source categories for CAC emissions have been defined, since there are different factors affecting growth in emissions from each category. These categories are:

- oil sands (including extraction, heavy oil and bitumen upgrading);
- conventional natural gas production (includes gas well testing, flaring and processing);
- conventional crude oil production (includes solution gas flaring).

3.6.1 Oil Sands and Upgraders

Many new projects have been announced for the extraction and upgrading of oil from the large oil sand reserves in Alberta. The table below shows estimates of capacity for various locations or projects.

Table 23: Capacity of Announced Oil Sands Projects

(barrels per day)

Company	Location/Project	2000	2005	2010
Syncrude	Fort McMurray	300,000	725,000	725,000
Suncor	Fort McMurray (Millenium, Firebag, Voyageur)	115,000	260,000	525,000
Shell	Scotford upgrader	0	177,000	177,000
Shell	Jackpine Mine	0	0	200,000
Albian Sands	Muskeg River Mine	0	155,000	155,000
OPTI	Burnt Lake Pilot	3,000	3,000	3,000
OPTI	Long Lake Project (in-situ and upgrader)	0	0	60,000
Northstar	Pilot (AOSTRA)	2,000	2,000	2,000
Imperial Oil Ltd.	Cold Lake	100,000	150,000	150,000
Imperial Oil Ltd.	Mahihkan and Nabiye	0	0	30,000
Conoco	Fort McMurray	0	0	50,000
Jacos	Fort McMurray Pilot	6,000	10,000	10,000
Jacos	Fort McMurray Commercial project	0	0	50,000
CNRL - Canadian Natural Resources Ltd.	Burnt Lake Pilot (capacity unknown)			
CNRL - Canadian Natural Resources Ltd.	Primerose and Wolf Lake	57,000	116,000	116,000
CNRL - Canadian Natural Resources Ltd.	Horizon Project (with onsite upgrader)	0	0	180,000
Pan Canadian	Christina Lake Thermal Project	0	0	85,000
Husky	Tucker and Lease 87	0	0	*143,000 (by 2015)*
Blackrock Ventures Inc.	Orion	0	10,000	20,000
Rio Alto Exploration Ltd.	Kirby			30,000
Alberta Energy	Foster Creek Expansion		100,000	100,000
Synenco	Firebag River		20,000	80,000
Exxon/Mobil	Kearl Oil Sands Mine (and Upgrader)			185,000
TrueNorth	Fort Hills Project			190,000
Petro-Canada	Meadow Creek			60,000
Petro-Canada	McKay River			22,000
Petro-Canada	Lewis Project			60,000

Source: Cheminfo Services, based on Environmental Impact Assessment (EIA) documents.

The announced capacity for production in the province does not match the announced increases in capacity for upgrading and oil refining. This study did not have the scope of developing estimates for potential new upgrader or oil refining capacities for which no public announcements have been made. The inherent implication is that the bitumen or oil may need to be exported from the province. This could result in conservatively low estimates for future CAC emissions, in that new upgraders may follow production. On the other hand, some of the projects announced may not come to fruition due to market, investment or other factors.

The major sources of CAC emissions from the oil sands activities include:

- fuel combustion (notably SOx from oil and coal, NOx and CO from all fuels);
- spent solvent emissions released from upgraders (VOC) to tailing ponds;
- sulphur recovery facilities (SOx);
- power (steam/electricity) generation equipment (all CACs); and
- operations of mining equipment (all CACs).

This is not a comprehensive list of the many, less significant potential sources of CAC emissions from oil sands mining and upgrading operations.

3.6.1.1 Emission Trends From Oil Sands and Upgraders

Between 1995 and 2000, most emissions from oil sands operations increased. This is a result of increased production, although environmental improvements curtailed the increase to some degree. A notable exception was a sharp decline in SOx emissions. This drop came about as a result of the installation of a flue gas desulphurization (FGD) unit at Suncor and operational improvements at Syncrude between 1996 and 2000. Suncor's FGD unit was installed to control a portion of the potential SOx emissions from the facility. With expansions in capacity, these companies anticipate adoption of increased levels of control to address future increases in potential SOx emissions. For example, Syncrude anticipates that their SOx emissions will drop even though their capacity for bitumen upgrading could increase to over 1 million barrel per day by 2020. As part of the expansion involving a new coker by 2005, the company will have installed a desulphurization unit to control coker emissions. Similar installations are anticipated for any future expansions.[25] Similarly, Suncor anticipates a probable requirement to install controls to address a greater portion of potential SOx emissions when their Voyageur expansion comes on stream in 2008.[26] The degree of adoption of emission controls (inherent in the EIAs reviewed for this study) are not explicitly available (although their cumulative effects on emissions are included in the emission estimates). Some facilities may not be applying any technologies to address SOx emissions.

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[25] Source: Syncrude

[26] Source: Suncor

Table 24: Forecast of Emissions from Oil Sands Developments

(Including upgraders) (kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	5	6	17	32	37	38	194%	442%	543%
PM10	2	3	9	18	20	21	210%	545%	630%
PM2.5	2	2	6	11	13	14	168%	408%	552%
SOx	164	94	117	162	164	164	25%	72%	74%
NOx	43	54	89	159	198	202	65%	195%	273%
VOC	56	61	125	280	301	304	104%	356%	395%

Many of the new oil sands projects will involve use of steam assisted gravity drainage (SAGD) technology. The Suncor Firebag project and the Petro-Canada's MacKay River projects are SAGD examples. This technology involves injecting steam underground to enhance flow to the surface. A major source of emissions from this process are the steam generating power plants (boilers), which will consume fossil fuel and result in combustion related emissions. Fuels to be used for steam and power generation include: natural gas, oil and even some coal. Energy is also required for upgrading operations. In some cases, companies are installing natural gas combined cycle (NGCC) facilities at the mine site to make electricity as well as steam. The emissions from these units are included as part of the oil sands development.

Upgrading the oil sands bitumen can involve the use of hydrocarbon solvents to separate the sand from the oil. In these situations, a substantial amount of solvent is required. This solvent can be produced from the upgrader itself. While much of this solvent is internally recycled, spent solvent, which is a small fraction of the total applied, is released to tailings ponds, from which a portion will evaporate. Industry sources contacted in this study point out there is uncertainty with respect to the portion of the solvent that actually evaporates. Some components in the solvent attach to the sand particles that are also sent to the tailings pond. Industry sources have provided their estimates of the total VOC emitted from these sources. This amount of solvent, which was nearly 60 kilotonnes in 1995, was not included in Alberta Environment's provincial or Environment Canada's national 1995 CAC emissions inventory.[27] It has been included in this Appendix.

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[27] Source: Alberta Environment

While only a small fraction of solvent is released, the total over a year can be substantial in proportion to other industrial VOC emission sources in Alberta. Suncor's and Syncrude's operations currently have large VOC emissions from this source. Other upgraders and oil sands mines expected to come into production will add to these VOC releases. One exception will be the Shell upgrader in Scotford. Shell's upgrader will receive a bitumen/solvent mix via pipeline from Albian Sands. The solvent is required to enhance the flow of the viscous bitumen. At the upgrader, the solvent will be separated from the bitumen, recovered and placed back into a pipeline for delivery back to Albian Sands. The amounts of VOC emissions from this process are anticipated to be low, although specific estimates were not available. At some other operations, spent solvents will be released to collection ponds.

3.6.2 Conventional Oil and Gas Production

NOx, VOC and CO emissions from conventional oil and gas production are projected to increase. SOx emissions from this segment of the oil and gas industry are projected to decline, as shown in the table below. Some of the major factors affecting forecast emissions include:

Factors that contribute to reduced emissions

- new AEUB sulphur recovery regulations for older (grandfathered) gas processing facilities;
- new AEUB gas flaring regulations for older (grandfathered) gas processing facilities;
- reduced conventional crude oil production;
- reduced solution gas flaring;

Factors that contribute to increased emissions

- increased natural gas production; and
- increased processing of gas with higher sulphur levels production.[28]

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[28] The potential effects of increased sulphur levels in gas were not incorporated in this forecast.

Table 25: Forecast of Emissions from Conventional Oil and Gas Production Activities

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	1	1	2	2	2	2	21%	30%	56%
PM10	1	1	2	2	2	2	21%	30%	56%
PM2.5	1	1	2	2	2	2	21%	30%	56%
SOx	276	260	238	230	227	225	-8%	-12%	-13%
NOx	256	292	324	346	366	378	11%	19%	30%
VOC	485	486	492	497	509	495	1%	2%	2%

SOx emissions related to conventional oil and gas production are projected to decrease. The major factors contributing to a slow decline are new sulphur recovery requirements for older gas processing facilities and reduced flaring. Partially offsetting these effects will be increases in gas production.

3.7 Petroleum Refining

There are five petroleum refiners in Alberta, although the Parkland refinery, which is currently idle, is a smaller facility largely involved with processing condensates.[29] The petroleum refining sector in Alberta, which services provincial demands as well as markets in other western Canadian provinces and the United States, is expected to continue to slowly increase its production capability. At the same time, some refiners are modifying their operations to accommodate the refining of more synthetic oil, as well as meet new environmental pressures, including reduced sulphur levels in fuels. Energy requirements and related CAC emissions are projected to increase.

3.7.1 Emission Trends

Most CAC emissions from the petroleum refining industry in Alberta are expected to increase slowly from year 2000 levels. Nevertheless, SOx emissions, which dropped between 1995 and 2000, will be lower than 1995 levels by 2020. All other CAC emissions are projected to be higher than 1995 levels by 2010 and 2020.

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[29] The inherent assumption in this forecast is that Parkland, which accounted for nearly 5% of SOx and 1% of NOx emissions in the sector in 2000, will resume operations by 2005.

Table 26: Forecast of Emissions from Petroleum Refining Sector

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	833	883	1043	1069	1123	1179	18%	21%	33%
PM10	832	882	1042	1068	1122	1177	18%	21%	33%
PM2.5	832	882	1041	1067	1121	1176	18%	21%	33%
SOx	15232	9755	8617	11987	12617	13247	-12%	23%	36%
NOx	3956	4599	4614	4757	4986	5222	0%	3%	14%
VOC	755	1136	767	793	832	872	-32%	-30%	-23%

Refiners in the province have been making operational changes that have resulted in environmental improvements. These include: implementation of leak detection and repair (LDAR) programs that can reduce hydrocarbon losses (i.e., VOCs); adoption of technologies to improve energy consumption and related fuel combustion emissions; and improved sulphur recovery. The trend towards environmental improvements is expected to continue. Inherent in this forecast of emissions are continuous incremental improvements in energy efficiency. Process changes at some refineries will also reduce SOx emissions by 2005, although increases in throughput will see SOx emissions increase from the sector.

3.8 Cement

There are two cement plants in Alberta with a total capacity of nearly 2180 kilotonnes per year or 800 tonnes per day of clinker. Cement production is projected to increase by approximately 10% by 2020 from year 2000 levels. All kilns in Alberta have historically used natural gas as the primary fuel source. However, all kilns are in the process of converting to the use of lower-cost coal. High natural gas prices in the year 2000 and 2001 were one factor that contributed to the cement plants converting to coal as the primary fuel source. These conversions will soon be complete and certainly operational before 2005 (likely by 2003).

3.8.1 Emission Trends

Emissions from the cement industry are projected to decrease slightly. The major factors contributing to changes in emissions include:

- conversion to coal use which tends to lower NOx emissions (versus natural gas);
- installation of new Low-NOx burners at one facility (which could reduce NOx emissions)[30];
- controls applied to reduce SOx by 25% from one facility by 2007 (lime injection, process control optimization are options the facility plans to adopt)[31]; and
- continued improvements in energy efficiency.

Table 27: Forecast of Emissions from Cement Industry

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	1788	1166	1162	1149	1155	1127	0%	-1%	-3%
PM10	465	386	390	388	387	378	1%	0%	-2%
PM2.5	124	117	118	118	118	115	1%	1%	-2%
SOx	3094	2790	2700	2058	2152	2149	-3%	-26%	-23%
NOx	7638	5000	4954	4836	4936	4814	-1%	-3%	-4%
VOC	36	41	41	40	41	40	1%	-2%	-2%

Although cements facilities will use more coal, which does contain sulphur, both producers claim that there should not be additional SOx emissions. The reason is that potential SOx emissions are "scrubbed" by the process itself (i.e., in the kiln), such that the sulphur contained in the fuel is not emitted. SOx emissions are more related to the amount of sulphur in the raw materials used.

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[30] Industry source. Highly uncertain NOx reduction. No guaranteed reduction was available from supplier.

[31] Industry source. SOx reduction options to be implemented to meet anticipated Alberta Environment pressures.

3.9 Chemicals

The chemicals sector (standard industry classification SIC-37, NAICS-32) encompasses a great variety of organic and inorganic chemical producers and formulators making: petrochemicals, polymers, fertilizers, coatings, oil field chemicals, inks, chlorine, acids, bases and many specialty products. The chemicals sector in Alberta may include as many as 100 to 150 companies of varying sizes, although 10 major petrochemical/polymer and fertilizer producers account for more than 70% of energy consumption and most of the chemical sector CAC emissions in the province.

Table 28: Contribution to SOx, NOx Emissions from Petrochemical, Fertilizer and Smaller Chemical Facilities

Chemical Segment	SOx	NOx	Estimated Number of Companies
Major petrochemicals/polymers plants	19%	44%	8-10
Major fertilizer plants	55%	39%	7-8
Estimated emissions from all other chemical facilities	26%	18%	80 to 120

The large petrochemical industry in Alberta has been growing quite rapidly and is projected to continue to grow. World-scale ethylene plants, as well as other petrochemical and polymer facilities have come on-stream in the last 10 years. CAC emission projections reflect increases in energy consumption associated with this increased production.

3.9.1 Emission Trends

Energy consumption is the major source of CAC emissions from most chemical operations. Emissions from the sector are, therefore, projected to increase with fuels used. Total energy consumption is not expected to increase at the same rate as production in the industry. Energy efficiency improvements are expected. As a notable example, Nova/Dow's "E 3" cracker is approximately 2 to 3 times less NOx emissions-intensive than the older "E 1" cracker. Energy and environmental improvements are projected for all of Nova's ethylene plants, other fertilizer and petrochemical plants as well as smaller operations that are relatively minor sources of emissions. Similar improvements are projected for other chemical facilities. Successive generations of ammonia fertilizer facilities have been designed and operated at a lower rate of natural gas consumption to product yield, and this trend is expected to continue.

Table 29: Forecast of Emissions from Chemicals Sector

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	1132	1556	1698	1831	2019	2197	9%	18%	41%
PM10	1062	1477	1617	1746	1932	2106	9%	18%	43%
PM2.5	438	621	683	741	823	901	10%	19%	45%
SOx	2161	2973	2976	2979	2983	2986	0%	0%	0%
NOx	23364	24499	26876	29077	32219	35181	10%	19%	44%
VOC	10554	12781	13340	13690	14463	14587	4%	7%	14%

3.10 Pulp and Paper

There are four kraft pulp mills in Alberta, which represent the majority of emissions from the sector in the province. Mechanical mills (such as chemi-thermomechanical - CTMP, TMP and stone groundwood) are electricity-intensive and, therefore, are generally less emissions-intensive than kraft mills. However, although emissions from the kraft mills can be odorous, the total amount of emissions is not usually high considering the mass of wood processed and total energy consumed. One factor is that these mills rely on biomass as a major source of fuel. Biomass, as spent liquor, is burned in the kraft recovery boilers. It can also be fired in power boilers for the production of steam. Biomass contains a very low amount of sulphur (therefore low SOx emissions), and with relatively high moisture content the biomass burns at temperatures and under conditions which result in relatively low NOx emissions per unit of energy consumed.

Two major pulp mills, which constitute the majority of emissions in the sector, have indicated they have lowered emissions in the last five years as a result of optimization of recovery boiler operations and application of some emission reduction technologies. Year 2000 SOx emissions reported to Alberta Environment have decreased from 1995 levels by 45 to 50% for the major facilities. Reported NOx emissions have decreased 10 to 15%. However, emissions are projected to increase with increased energy use.

Table 30: Forecast of Emissions from Pulp and Paper Sector

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	2088	1953	2217	2482	2682	2879	13%	27%	47%
PM10	1874	1778	2017	2258	2439	2619	13%	27%	47%
PM2.5	1770	1703	1928	2160	2333	2506	13%	27%	47%
SOx	3840	2036	2561	2814	3004	3193	26%	38%	57%
NOx	4430	3800	4233	4758	5171	5574	11%	25%	47%
VOC	43	49	55	62	67	72	11%	25%	46%

Source: Alberta Environment for year 2000 NOx and SOx emission. Other year 2000 emissions and projections by Cheminfo Services.

3.11 Iron and Steel

Alberta's iron and steel sector includes AtlaSteel's Ltd. mini-mill, which uses an electric arc furnace (EAF) process, as well as integrated billet production and rolling operations. Raw material for the steel making operations is recycled steel. Mini-mill operations are typically smaller, less energy and emissions-intensive than integrated steel mills, which include blast furnaces for iron ore reduction and basic oxygen furnaces for steel making. At AtlaSteel's mini-mill, the metal is first placed in a melting furnace. Electricity - passed through graphite electrodes, and natural gas - fired through side ports - provide energy sources to heat and melt the recycled metal. The melted metal is transferred to a ladle furnace where it is formulated to meet specific application requirements. Billets are cast, rolling is carried out and bar products are made at integrated AtlaSteel Edmonton operations.

Table 31: Forecast of Emissions from Iron & Steel Sector

(tonnes)

Contaminant	1995[32]	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	249	188	254	267	280	294	35%	42%	56%
PM10	210	159	214	225	236	248	35%	42%	56%
PM2.5	79	61	82	86	90	95	35%	42%	56%
SOx	81	17	17	17	17	17	0%	1%	1%
NOx	241	167	220	230	240	251	31%	37%	51%
VOC	1	1	1	2	2	2	32%	38%	51%

Major emission sources include the combustion of fuels (mostly natural gas) and as well process emissions from the melting and ladle furnaces. The furnaces are a significant source of potential PM emissions. However, a baghouse at the AtlaSteel plant captures the majority of the potential emissions.

Emission projections for Alberta's iron & steel sector take into account AtlaSteel's expansion in 2001. The facility increased its capacity by 35%, and although production has yet to match the capability of the plant, production will be increased to capacity levels before 2005. Thereafter production and emissions are projected to increase slowly to the year 2020, which would require additional investment.

3.12 Non-Ferrous Metals Smelting & Refining Sector

There are no major sources of SOx emissions within the non-ferrous metal smelting & refining operations in Alberta, as there are in Ontario, Quebec, Manitoba and British Columbia. One facility in Alberta included in this sector is an Alcan Inc. operation making carbon raw material for the ultimate production of carbon anodes (made at other locations in Canada). Among other potential uses, carbon anodes are used in primary aluminum smelting, which is largely based in Quebec. The sector also includes any small facilities upgrading some non-ferrous minerals in Alberta. (Sherritt International operates a nickel leaching/refining operation in Fort Saskatchewan. There are SOx emissions from its sulphuric acid plant. However, the sulphuric acid plant is considered part of the chemicals sector.)

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[32] In 1995, there were two mini-mill operations in Alberta. Ipsco Steel operated a mini-mill that was closed during 1995.

Alcan's emissions are the major contributor to non-ferrous metal smelting & refining sector's emissions in Alberta. SOx emissions are the most notable. These result from the sulphur contained in the petroleum coke, which is heated to make the carbon product. Only a minor portion of the sulphur is vapourized from the coke. Most of it remains in the final carbon product shipped to anode manufacturing sites. The hot gas stream from the coke heating containing the sulphur as well as VOCs, hydrogen, CO and other components is burned before release to the atmosphere. Some heat is recovered, so fossil fuel purchases are minimized.

Alcan has no plans for any major new expansions, since it is always a challenge to acquire suitable grades of petroleum coke for the Alberta site. However, according to Alcan, production of carbon anodes will creep up slowly - by 1% per year - or by a total of 20% to 25% between 2000 and 2020. Even with this increase, SOx emissions will remain below the facility's current emission limits.

Table 32: Forecast of Emissions from Non-Ferrous Metals Smelting & Refining Sector

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	13	15	15	16	17	18	5%	10%	22%
PM10	12	14	14	15	16	17	5%	10%	22%
PM2.5	10	12	12	13	14	14	5%	10%	22%
SOx	2515	3785	3978	4181	4394	4619	5%	10%	22%
NOx	338	421	443	465	489	514	5%	10%	22%
VOC	1	2	2	2	2	2	5%	10%	22%

3.13 Transportation

Transportation emission sources include on-road and non-road vehicles. On-road vehicles include the major vehicle emission sources, namely: light and heavy-duty gasoline and diesel vehicles (passenger cars and trucks); as well as small road vehicles such as motorcycles. Non-road vehicles include: gasoline and diesel farm vehicles (e.g., tractors, combines, etc.); rail locomotives; boats; and aeroplanes and airport vehicles. A forecast of on-road emissions was recently prepared for Environment Canada and the Emissions and Projections Working Group (EPWG) of the National Air Issues Co-ordinating

Committee – Other Air Issues (NAICC-A).[33] This analysis reflects the results of that study for on-road vehicles. Non-road vehicle emissions are handled differently.

3.13.1 Emission Trends

Most transportation emissions are projected to decrease. However, in a base case SOx emissions are projected to remain relatively constant versus 2000 levels, since non-road emissions are dominant, especially after 2005 (when much of the sulphur has been removed from on-road gasoline). SOx emissions are examined more closely below in the following section on "SOx Sensitivity".

Table 33: Base Case Forecast of Emissions from Transportation in Alberta

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	12.8	10.5	7.6	5.8	5.1	5.2	-27%	-45%	-51%
PM10	12.3	10.0	7.2	5.4	4.7	4.7	-27%	-46%	-53%
PM2.5	11.2	9.0	6.4	4.6	3.9	3.9	-29%	-49%	-57%
SOx	7.5	11.0	10.2	9.3	9.6	10.3	-8%	-16%	-6%
NOx	227.2	227.4	165.9	126.2	101.6	95.5	-27%	-45%	-58%
VOC	104.8	75.9	51.0	38.4	33.9	34.5	-33%	-49%	-54%

Source: Environment Canada. Cheminfo Services for some non-road sources.

Total CAC emissions from **on-road** transportation sources are projected to decrease despite increased fleet sizes, total distances travelled and greater fuel requirements. Inherent in the reductions are the incorporation of improved emission standards. Vehicle manufacturers will be required by the US EPA to make vehicles that meet the so called Tier II standards. Tier II standards reflect major reductions in NOx and other CAC emissions.

The reduction in CAC emissions is, in part, also due to cleaner fuels. Environment Canada's 1999 *Sulphur in Gasoline Regulations*[34], will require that gasoline have a sulphur content of less 0.0030% by weight (or 30 ppm) after January 1, 2005. Currently, sulphur levels in gasoline in Alberta, which are in the range of 150 to 250 ppm (varying by refinery) are already low in comparison to other Canadian provinces. The higher use of synthetic crude oil is a contributing factor for lower sulphur levels. Emissions are also expected to decrease from on-road diesel vehicles. On-road national diesel standards will require 15 ppm sulphur levels by 2007.

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[33] Senes Consultants Limited / Air Improvement Resource, Inc., *Updated Estimate of Canadian On-Road Vehicle Emissions For The Years 1995-2020*, December 2001.

[34] Government of Canada, *Sulphur in Gasoline Regulations* (SOR/99-236), Registration 4 June, 1999 Canadian Environmental Protection Act, 1999. http://laws.justice.gc.ca/en/C-15.31/SOR-99-236/text.html

Reducing sulphur in gasoline enables emissions control technology and yields collateral environmental benefits for CAC and toxics pollutant emissions. NOx, CO, VOC and PM emissions are all projected to decrease as a result of market penetration of vehicles with improved emission control technologies, including improvements to combustion and catalytic systems and using lower sulphur fuels.

Table 34: Forecast of Emissions from On-Road Vehicles

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	6.2	5.1	3.6	2.3	1.8	1.7	-29%	-54%	-66%
PM10	5.9	4.9	3.5	2.2	1.6	1.5	-29%	-56%	-69%
PM2.5	5.4	4.3	2.9	1.7	1.1	1.0	-32%	-61%	-77%
SOx	1.9	2.5	1.4	0.2	0.2	0.3	-45%	-91%	-89%
NOx	139.8	134.9	91.4	56.7	32.3	22.3	-32%	-58%	-83%
VOC	81.5	59.4	38.4	27.3	22.9	22.7	-35%	-54%	-62%

Source: Environment Canada.

CAC emissions from **non-road** vehicles such as off-road diesel vehicles, rail locomotives, aircraft, and boats are projected to decrease (except for SOx) in the base case. These changes reflect new standards for off-road vehicles that are similar in nature to on-road vehicles, since the emissions for off-road were estimated based on results for on-road MOBILE 5C+ and Part 5C.[35] New Standards for off-road gasoline and diesel vehicles under development in the United States are expected to spill over into Canada's off-road vehicle fleet in this decade.

A similar influence is expected to occur in rail transportation. Canada's aging fleet of rail locomotives is gradually being replaced with new locomotives that are more energy efficient and less emissions-intensive. These new locomotives will be purchased in the United States, where locomotive manufacturers are implementing designs to meet U.S. EPA emission standards. The result of increased market penetration of new locomotives in Canada's fleet will be to reduce NOx emissions by at least 25% by 2020 from year 2000 levels, according to the Rail Association of Canada. This NOx reduction has been incorporated in this forecast. While the new locomotives are also likely to feature lower emission rates for other CACs, these are more difficult to quantify and, therefore, have not been incorporated in the forecast.

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[35] Environment Canada, Pollution Data Branch, *Development of the NAICC Base Case Consensus Forecast of Common Air Contaminants 1995 – 2020*, March 2002.

There has been steady improvement in the overall energy-efficiency of Canada's locomotive fleet (averaging 2% to 3% per year).[36] Continued improvements are expected, albeit at lower annual improvement rates (e.g., 0.5% to 1% per year). In the context of these improvements and increased workload (tonnes carried) fuel consumption is expected to increase very slowly in the forecast period (as reflected by CEOU).

Table 35: Forecast of Emissions from Non-Road Vehicles

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	6.6	5.4	4.0	3.5	3.3	3.5	-25%	-35%	-36%
PM10	6.4	5.1	3.8	3.2	3.0	3.2	-26%	-37%	-38%
PM2.5	5.8	4.7	3.4	2.9	2.7	2.9	-26%	-37%	-38%
SOx	5.6	8.6	8.8	9.1	9.3	10.1	3%	6%	18%
NOx	87.4	92.5	74.5	69.5	69.3	73.2	-19%	-25%	-21%
VOC	23.3	16.5	12.6	11.1	11.0	11.8	-24%	-32%	-28%

Source: Environment Canada, Cheminfo Services, Rail Association of Canada

3.14 Residential Heating

Most CAC emissions from residential buildings are from the combustion of fuel wood, which is quite CAC-intensive. Increased use of residential fuel wood drives projected increases in CAC emissions for the category as a whole. Partially offsetting this trend is increased market penetration of natural gas, which accounts for over 95% of the fossil fuel use, and reduction of sulphur-containing fuel oils. This has the effect of lowering SOx emissions. However, an increase in the small amount of coal (1% of fossil fuel use) that is used in residential buildings will result in an increase in SOx emissions.

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[36] Rail Association of Canada, *Locomotive Emissions Monitoring Programme 1999-2000.* http://www.ec.gc.ca/transport/publications/rail2000/rail2.htm

Table 36: Portion of Residential CAC Emissions from Fuel Wood Combustion

Contaminant	2000	2005	2010
PMT	90%	90%	91%
SOx	46%	33%	34%
NOx	12%	14%	15%
VOC	99%	99%	99%

Table 37: Forecast of Emissions from Residential Buildings

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	8682	10750	11946	13029	14107	16200	11%	21%	51%
PM10	8429	10574	11640	12702	13779	15909	10%	20%	50%
PM2.5	7984	10057	11009	12008	13031	15069	9%	19%	50%
SOx	425	302	466	500	516	502	54%	65%	66%
NOx	7033	7450	6974	6905	7016	7166	-6%	-7%	-4%
VOC	36544	46856	51965	57099	62248	72539	11%	22%	55%

3.15 Commercial/Institutional Buildings Heating

Fuel wood is not significantly used in commercial and institutional buildings. Therefore the two major factors affecting forecast estimates of emissions are continued energy efficiency improvements and reduced market share of fuel oil containing sulphur, which reduces SOx emissions. Similar base case energy-efficiency improvements have been incorporated within CEOU's fuel consumption data, resulting in a decrease in the use of total fossil fuels in the province for these types of buildings.

Table 38: Forecast of Emissions from Commercial and Institutional Buildings

(tonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	530	500	494	475	460	449	-1%	-5%	-10%
PM10	520	489	484	466	452	442	-1%	-5%	-10%
PM2.5	510	479	475	457	445	434	-1%	-5%	-9%
SOx	389	653	446	386	207	88	-32%	-41%	-87%
NOx	5444	5285	5088	4877	4735	4623	-4%	-8%	-13%
VOC	260	247	242	233	227	222	-2%	-6%	-10%

3.16 Non-Energy and Natural Area Sources of Emissions

Major non-energy-related and natural area sources of CAC emissions include particulate emissions of road dust, forest fires (PM, NOx, VOC), biogenic sources (mostly VOC from vegetation and decay) and many anthropogenic sources such as prescribed burning, structural fires, cooking, tobacco smoking, solvents emissions from painting, printing, adhesives, and many other sources. Non-energy-related and natural area sources are large and can potentially dominate regional emissions. (Note the units in the table that follows are kilotonnes).

Table 39: Total Emissions of Non-Energy Area and Natural Sources

(kilotonnes)

Contaminant	1995	2000	2005	2010	2015	2020	Change2000 to 2005	Change 2000 to 2010	Change 2000 to 2020
PMT	4886	5654	6262	6756	7225	7940	11%	19%	40%
PM10	1460	1658	1821	1953	2084	2277	10%	18%	37%
PM2.5	206	229	251	268	288	315	9%	17%	37%
SOx	0.2	0.2	0.2	0.2	0.2	0.2	5%	11%	24%
NOx	31	31	31	31	31	31	0%	0%	0%
VOC	1355	1357	1361	1366	1372	1378	0%	1%	2%

Simplifying assumptions have been applied to project CAC emissions among the many sources within this broad category. Biogenic and forest fires emissions have been kept constant to 1995 levels. In general, increases in anthropogenic emissions have been calculated using surrogates of human activity (e.g. road dust increased with distance travelled, smoking emissions with population, etc.) The parameters on which various projections are based can be found in an earlier report by Cheminfo Services[37].

3.17 Focus: Analysis of CAC Emissions in Critical Air sheds

This section provides an overview of the regional SOx, NOx and VOC emissions forecast for the three most important Alberta air shed regions in terms of emissions, as represented by 4 of 19 census regions in the province. The census regions are: #6 covering Calgary and the surrounding area; #11 covering Fort Saskatchewan/Edmonton/Wabamun and the surrounding area; and #12 and #16 that cover the north-east area of the province and encompass all current and future oil sands projects. The analysis that follows is based on a forecast of Alberta emissions for these census regions conducted by Cheminfo Services (Clean Air Strategic Alliance- CASA, 2002)[38]. The Cheminfo study applied regional allocations for area sources, upstream oil and gas process (excluding oil sands) and small point sources, as provided by the CASA, and as estimated by RWDI West Inc. (2001).[39] Emissions from large point sources (including oil sands projects) were attributed to specific census regions where they were located.

In terms of emissions of NOx, SOx and VOCs in the three major census regions of interest in Alberta, the oil and gas sector (including upstream installations, existing and new oil sands projects) are by far the major contributors of emissions for both the area surrounding Calgary and the northeastern regions of Alberta. SOx and VOC emissions in both of these regions are dominated by the oil and gas processing sectors. NOx emissions in the heavily populated region 6 are also affected by transportation emissions, but these emissions are expected to decline over the next 20 years due to improved fuel and automobile standards. Emissions of all three pollutants in regions 12 and 16 are expected to increase dramatically over the 20-year period due to the upcoming oil sands projects.

In addition to emissions from the upstream oil and gas sector in the region surrounding Edmonton, electric power generation is a significant contributor of NOx and SOx. Although the region is heavily populated, significant reductions in emissions from transportation over the 20-year period in the region are projected to be largely offset by growth in emissions from other minor sources.

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[37] Cheminfo Services, *Alberta Emissions Forecast*, for Alberta Environment, June 2002.

[38] Cheminfo Services, *Alberta Emissions Forecast*, for Alberta Environment, June 2002.

[39] RWDI West Inc., Alberta Emissions Inventory in Support of Particulate Matter and Ozone Modelling July 13, 2001

Forecasted emissions of SOx, NOx and VOCs in the 3 major regions are given in the following tables.

3.17.1 Regional SOx Emissions

While total SOx emissions for Alberta are only projected to increase by approximately 9% by 2020, emissions from the three major regions vary substantially. SOx emissions in the region encompassing Calgary and surrounding communities are projected to decrease by approximately 12% between 2000 by 2020. In contrast, both the region surrounding Edmonton and the Oil Sands Areas are projected to experience increases in SOx emissions. Emissions of SOx in region 11 are projected to increase by 10%, while SOx emissions from both region 12 and region 16 are projected to increase by more than 50%.

Table 40: SOx Emissions by Census Region: 2000-2020

(tonnes)

Region	2000	2005	2010	2015	2020	% Change
6	68391	62860	60777	60021	59963	-12%
11	94757	107078	103120	103602	104451	10%
12	8128	11377	11418	12560	12550	54%
16	100024	106507	152177	152852	153163	53%
Alberta	515157	519079	561433	561448	562426	9%

Source: Cheminfo Services Inc.

SOx emissions from region 6 by major source are shown in the figure below. The oil and gas sector is by far the major contributor to SOx emissions from the region, representing approximately 95% of total anthropogenic emissions. A minor contributor is transportation, as this is a highly populated region of Alberta. Other anthropogenic sources such as electric power generation, heating in commercial and residential buildings and other industrial processes are not significant contributors of SOx in this region. Emissions from upstream oil and gas sector processes in the Calgary area are projected to decrease in the next 20 years due to process improvements and increased levels of environmental controls.

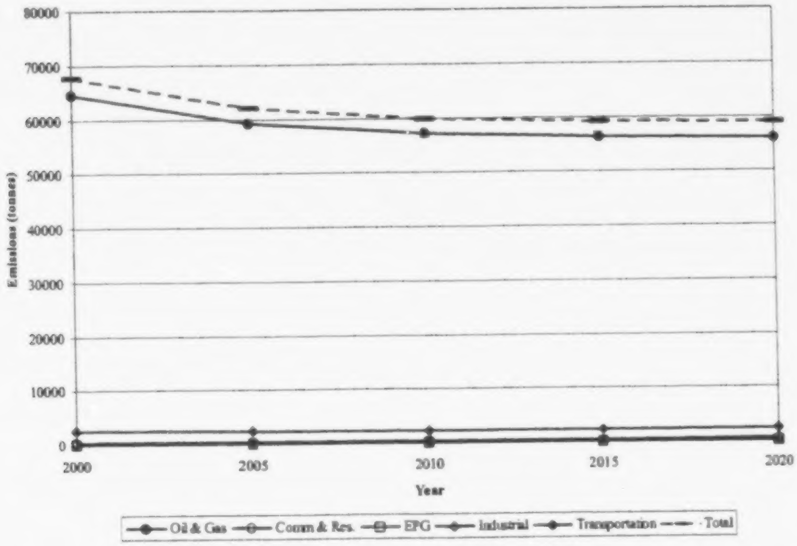

Figure 2: SOx Emissions from Major Source Categories in Region 6

Region 11 SOx emissions are shown in the figure below. The major contributing sources for Edmonton and the surrounding area contrast with those in the Calgary area. Electric power generation (EPG), oil and gas and other industrial processes are all significant contributors to the SOx emissions for the region. While both EPG and other industrial emissions in the region are projected to remain similar to current levels by 2020, the expected start-up of a bitumen upgrader prior to 2005 outside of Edmonton is the primary cause for regional SOx emissions growth. An increase in SOx emissions from EPG can be seen in 2005 due to the start-up of new generating stations in the region despite the shutdown of older generating stations in the same region.

As expected, SOx emissions in the northeastern regions are dominated by oil sands projects (shown below). These are projected to increase dramatically due to new installations expected to start up between 2000 and 2015. As these are sparsely populated areas with little industry outside of the oil and gas sector, other forms of anthropogenic emissions are not major contributors in this region.

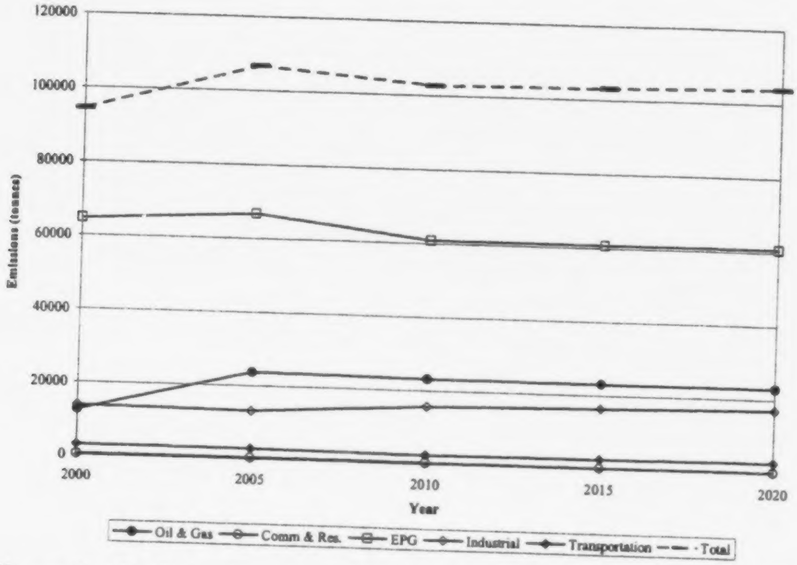

Figure 3: SOx Emissions from Major Source Categories in Region 11

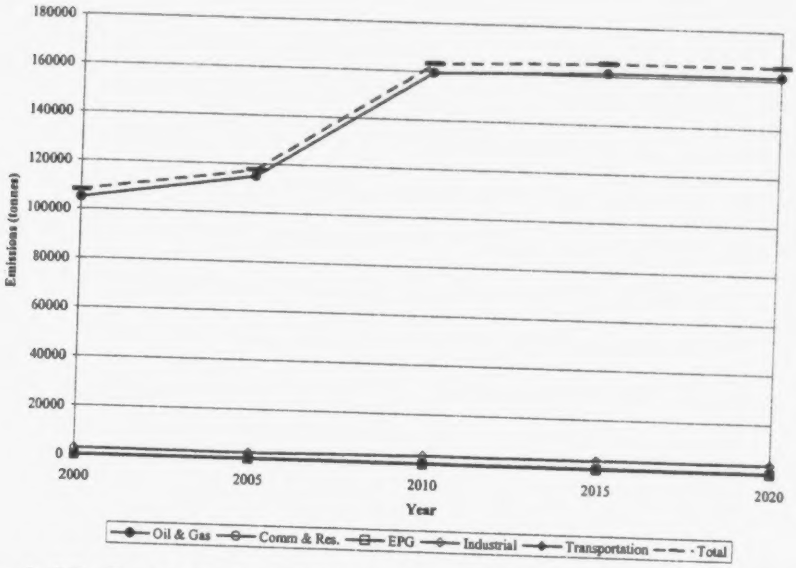

Figure 4: SOx Emissions from Major Source Categories in Regions 12 and 16

3.17.2 Regional NOx Emissions

NOx emissions for Alberta are projected to increase by approximately 18% by 2020. Large increases in NOx emissions are anticipated from the oil sands projects. However, NOx emissions are projected to decrease in the major urban areas. NOx emissions from the regions surrounding Calgary and Edmonton (regions 6 and 11, respectively) are projected to decrease by 11% and 7%, respectively, largely due to reductions from vehicle sources. NOx emissions from regions 12 and 16 are projected to increase by 48% and 201% by 2020, respectively.

Table 41: NOx Emissions by Census Region: 2000-2020

(tonnes)

Region	2000	2005	2010	2015	2020	% Change
6	91901	81993	80448	79619	81483	-11%
11	180748	174086	166957	165449	168698	-7%
12	24409	29784	30923	35425	36045	48%
16	69085	97234	168191	203550	207857	201%
Alberta	771150	782561	850649	890524	906962	18%

Source: Cheminfo Services Inc.

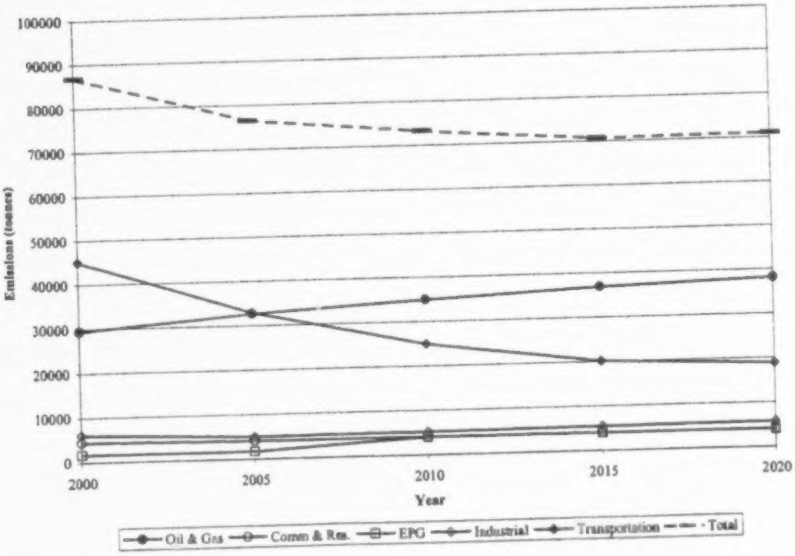

Figure 5: NOx Emissions from Major Source Categories in Region 6

NOx emissions from major source categories in region 6 are shown in the figure above. Oil and gas and transportation are major contributors of NOx emissions in the region, both ranging between 30% to 55% of total anthropogenic emissions. Large decreases in transportation emissions projected over the next 20 years are partially offset by increases in emissions from the oil and gas sector. Other industrial, commercial and residential sectors are minor contributors to NOx emissions in the sector, representing approximately 15% to 20% of emissions.

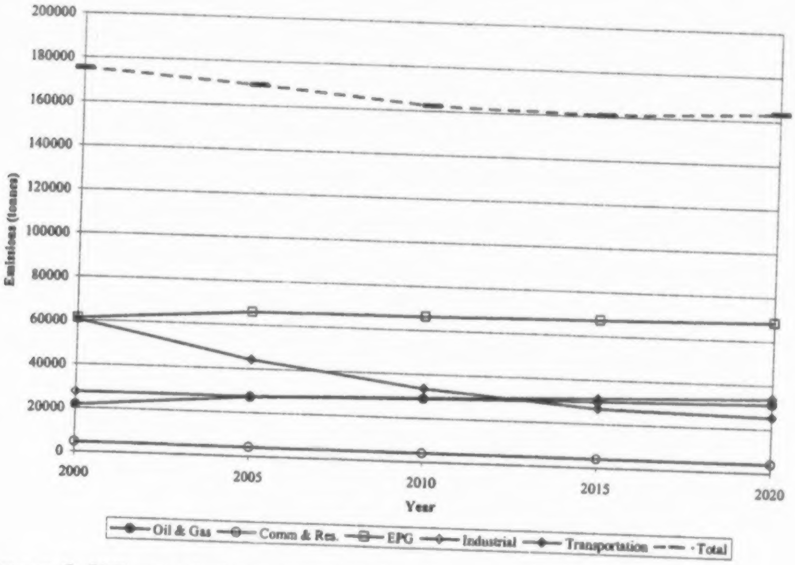

Figure 6: NOx Emissions from Major Source Categories for Region 11

Region 11 NOx emissions are shown in the figure above. Electric power generation, oil and gas, and transportation are all significant contributors to the NOx emissions for the region, representing approximately 80% of total anthropogenic emissions combined. Significant decreases in transportation emissions in the 20-year period are offset by increases in both EPG and oil and gas emissions.

As expected, NOx emissions in the northeastern regions are dominated by oil sands projects (shown below). These are projected to increase dramatically due to new installations expected to start up between 2000 and 2015. As these are sparsely populated areas with little industry outside of the oil and gas sector, other forms of anthropogenic emissions are not major contributors in this region.

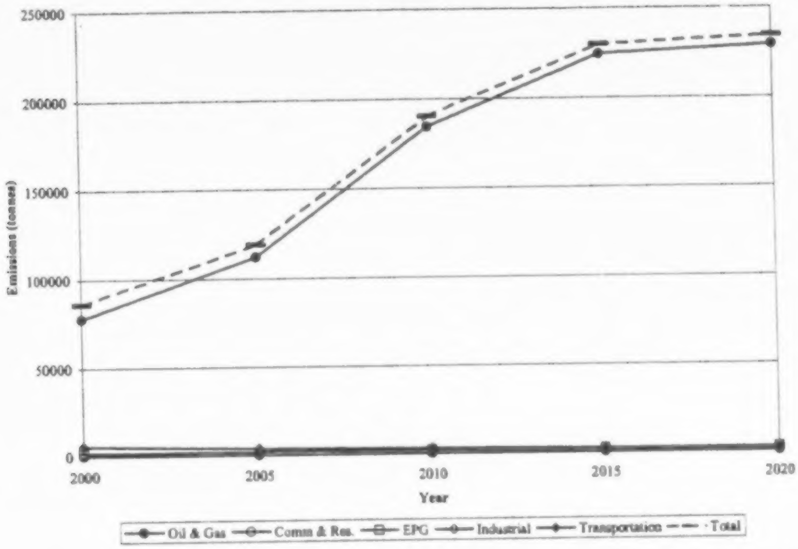

Figure 7: NOx Emissions from Major Source Categories for Regions 12 and 16

3.17.3 VOC Emissions

VOC emissions for Alberta are projected to increase by approximately 13% by 2020. VOC emissions are projected to be relatively constant in both major urban areas over the 20-year period. Emissions from the regions surrounding Calgary and Edmonton (regions 6 and 11, respectively) are projected to decrease by 2% and 1%, respectively. However, emissions from the oil sands projects are expected to increase substantially. VOC emissions from regions 12 and 16 are projected to increase by 4% and 168% by 2020, respectively.

Table 42: VOC Emissions by Census Region: 2000-2020

(tonnes)

Region	2000	2005	2010	2015	2020	% Change 2000 to 2020
6	633433	633852	636857	643974	644397	2%
11	551661	548888	549717	554377	557863	1%
12	46162	46601	46851	48047	47901	4%
16	143783	207310	362705	383880	386056	168%
Alberta	2044579	2098011	2256324	2296322	2303047	13%

Source: Cheminfo Services Inc.

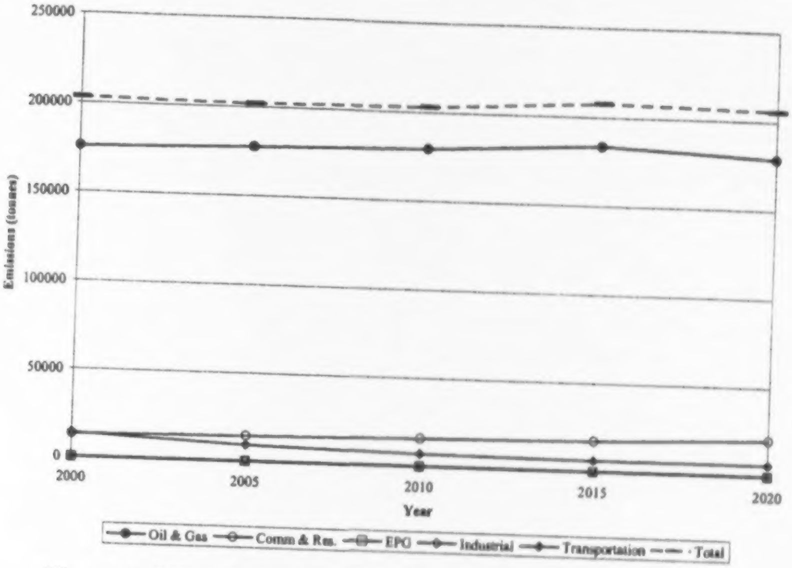

Figure 8: VOC Emissions from Major Sources in Region 6

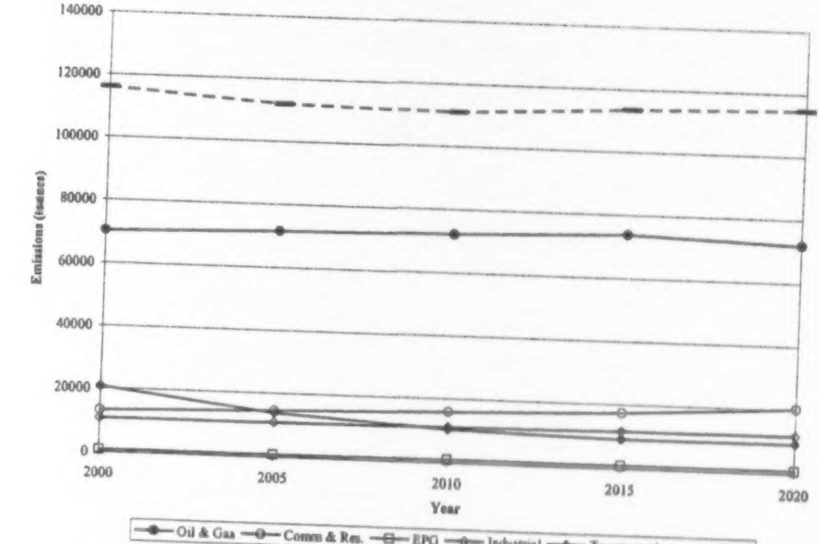

Figure 9: VOC Emissions from Major Source Categories in Region 11

VOC emissions from major sources in region 6 are shown in the figure above. The oil and gas sector is the most significant contributor to VOCs, ranging from 80 to 90% of total anthropogenic emissions in the region. The transportation, commercial and residential sectors are minor contributors to VOC emissions in this region. Decreases in VOC emissions from the transportation sector are offset by minor increases in the other sectors.

Similarly, the oil and gas sector is the most significant contributor to VOCs in region 11 (shown above), ranging from 60 to 65% of total anthropogenic emissions in the region. The transportation, commercial and residential sectors are more significant contributors to VOC emissions in the Edmonton area than in the Calgary area. Again, any decreases in VOC emissions from the transportation sector are offset by minor increases in the other sectors.

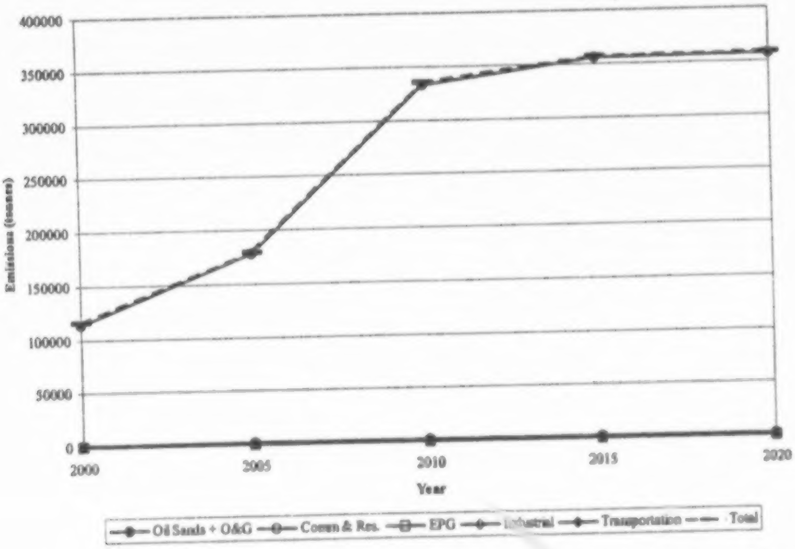

Figure 10: VOC Emissions from Major Source Categories in Regions 12 and 16

The only significant anthropogenic source of VOCs from the northeastern regions are the oil sands projects, representing approximately 99% of anthropogenic emissions. The start-up of many oil sands projects expected between 2000 and 2015 is projected to result in a growth in VOC emissions from this sector of approximately 214%.

4. Mercury Emissions

4.1 Mercury Emissions in Alberta

A total of approximately 0.8 tonnes of mercury were emitted to air by major point sources in Alberta in the year 2000. This total includes the facilities reporting to Environment Canada's National Pollutant Release Inventory (NPRI) program. Historical data are not provided, since it was not until the year 2000 that the NPRI mandatory reporting threshold for mercury releases/transfers was lowered to 5 kilograms per year (previously 10 tonnes/year of mercury manufacture, process or use). Outlined below are the mercury emissions reported to the NPRI from sources in Alberta. Estimates for natural sources of emissions of mercury are not available.

Table 43: Year 2000 Mercury Emissions in Alberta

(kilograms)

Company Name	Facility Name	City	Air (Stack)	% of Total Emissions
TransAlta Corporation	Sundance Generation Plant	Duffield	283	35%
Edmonton Power (EPCOR)	Genesee Generating Station	Warburg	104	13%
TransAlta Corporation	Keephills Generating Plant	Duffield	102	13%
ATCO Electric	Battle River Generating Plant	Forestburg	102	13%
ATCO Electric	Sheerness Generating Station	Hanna	75	9%
TransAlta Corporation	Wabamun Generating Plant	Wabamun	54	7%
Syncrude Canada Ltd.	Mildred Lake Plant Site	Fort McMurray	27	3%
Sensor Environmental	Swan Hills Treatment Centre	Swan Hills	15	2%
Daishowa-Marubeni Intl.	Peace River Pulp Division	MD of Northern Lights	10	1%
AltaSteel Ltd.*	AltaSteel Ltd.	Edmonton	10	1%
Lafarge Canada Inc.	Exshaw Plant	Exshaw	7	1%
ATCO Electric	H.R.Milner Generating Station	Grande Cache	6	1%
Suncor Energy Inc.	Suncor Energy Inc. Oil Sands	Fort McMurray	5	1%
Imperial Oil	IOL Strathcona Refinery	Edmonton	1	<<1%
Petro-Canada	Edmonton Refinery	Edmonton	1	<<1%
Shell Canada Products	Shell Scotford Refinery	Fort Saskatchewan	1	<<1%
Total			801	

* Source: NPRI[40]. AltaSteel reported 0.03 kg of air emissions from storage, which is included in this total. Rounded to nearest kilogram. Does not add to total due to rounding.

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[40] Environment Canada, *National Pollution Release Inventory (NPRI)*, Database http://www.ec.gc.ca/pdb/npri/npri_home_e.cfm.

Three companies operating six facilities account for close to 90% of the 0.8 tonnes per year of mercury emissions in the province. These six plants are the coal-fired electric generating facilities operated by ATCO Electric, Edmonton Power (EPCOR), and TransAlta Utilities. Based on submissions to the NPRI, it is estimated that Canada's electric power generating power sector in Canada releases 34% of mercury emissions.[41]

4.2 Regional Mercury Emissions in Alberta

With respect to a regional analysis of coal-fired power plant mercury emissions, the majority of these emissions (i.e. 75%) occur within Region 11 (i.e. Edmonton/Fort Saskatchewan/Wabamun area) in Alberta. Smaller amounts of mercury are emitted in Region 7 (Battle River) and Region 4 (Sheerness) from coal-fired power plants.

Table 44: Regional Analysis of Mercury Emissions from Coal-Fired Power Plants in Alberta

Power Plant	Region	Emissions (kg)	Regional Percentage of Major Coal-Fired Power Plant Emissions
Sundance Generation Plant	11	282.879	
Genesee Generating Station	11	104.000	
Keephills Generating Plant	11	101.729	
Wabamun Generating Plant	11	53.920	
Total Region 11		**542.528**	**75%**
Battle River Generating Plant	7	101.525	14%
Sheerness Generating Station	4	75.475	11%
Total		**177**	**100%**

4.3 Speciated Emissions of Mercury

Mercury primarily exists in two forms in flue gas, specifically in elemental and ionic forms. Some of the mercury is adhered to particulate matter contained in flue gases. Elemental mercury is more difficult to capture with existing emission control technologies than the ionic form of mercury, since is not very reactive and behalves like a gas at elevated temperatures, as those present in flue gas. The various coal types used by electric power plants (i.e., bituminous, sub-bituminous, lignite, anthracite) have different mercury emissions profiles, with respect to the release of elemental vs. ionic mercury. Six of the seven coal-fired electric power plants in Alberta use sub-bituminous coal, which results in high (i.e., 70 to 90%) elemental mercury emissions vs. ionic mercury emissions. Elemental mercury is less reactive than the ionic form, which results in greater local deposition of the ionic form, and long range transport of the elemental.

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[41] Lura Consulting, *Record of National Stakeholder Meeting Canadian Council of Ministers of the Environment, Mercury Canada-wide Standard for Electrical Power Generating Sector*, November 27, 2001.

Table 45: Coal Burned and Mercury Species Emitted From Coal-Fired Electric Power Plants in Alberta

Plant Name	Type of Coal Burned	Species Ratio (Elemental : Ionic)
Sundance Generation Plant	Sub-bituminous	Approx. 85:15
Genesee Generating Station	Sub-bituminous	Approx. 79:20
Keephills Generating Plant	Sub-bituminous	Approx. 71:29
Battle River Generating Plant	Sub-bituminous	Approx. 88:12
Sheerness Generating Station	Sub-bituminous	Approx. 81:19
Wabamun Generating Plant	Sub-bituminous	Not Available
H.R.Milner Generating Station	Bituminous	Not Available

Source: Senes Consultants, *Evaluation of Technologies for Reducing Mercury Emissions from the Electric Power Generation Sector*, February, 2002.

4.4 Stack Monitoring of Mercury

Currently, there are issues associated with more accurately estimating mercury emissions from coal-fired power plants in Alberta as well as verifying mercury emission reductions. This is attributed to the fact that mercury continuous emissions monitors (CEMs) have not been verified (as of October, 2000) in the U.S. For instance, at the time of the implementing the hazardous waste incinerator regulations in the U.S. (late 1999), the EPA stated that mercury CEMs did not appear to be rugged or accurate enough for compliance applications and have, therefore, not been validated. Additional research is required to determine the current state of acceptability of mercury CEMs in North America.

4.5 Mercury Emissions from Natural Sources

It has been suggested that the principal sources of mercury emissions from natural sources in Canada are soil, freshwater and marine surfaces, vegetation, and forest and bush fires. There is a large degree of uncertainty about the percentage of total mercury released that is emitted by natural sources. However most Canadian assessments have concluded that natural sources of mercury are a significant contributor to the overall global biogeochemical cycle and may account for up to half of the total mercury loading.[42]

4.6 Forecast of Mercury Emissions

A preliminary forecast of mercury emissions from the coal-fired electric generating sector in Alberta is provided below. The estimates are based upon the AMG forecast of coal-fired generation in Alberta as contained in *Canada's Emissions Outlook: An Update* (with February/March 2002 revisions, which include new plants). Mercury emissions are projected based upon an extrapolation of gigawatt-hours of electricity generated from coal. A more refined mercury emissions inventory may be necessary to take into account the co-lateral benefits (i.e. mercury emissions reduction) of emission controls installed for other pollutants, the type of coal being used by new power plant expansions in the province, etc. All other sources of mercury have been projected to remain constant.

Table 46: Forecast of Mercury Emissions From Coal-Fired Power Plants and Other Sources in Alberta

Year	Coal Fired Power Plants	All Other Sources	Total Estimated Emissions
	(tonnes)	(tonnes)	(tonnes)
2000	0.7	0.1	0.8
2005	0.8	0.1	0.9
2010	0.9	0.1	1.0
2015	0.9	0.1	1.0
2020	0.9	0.1	1.0

Source: Cheminfo Services estimates; Natural Resources Canada, *Canada's Energy Outlook*; Environment Canada, National Pollutant Release Inventory.

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[42] Government of Canada, *Submission by Canada to UNEP Global Mercury Assessment*, September 2001.

4.7 Uncertainty in Mercury Emission Estimates

Mercury emission estimates from coal-fired electric generating plants are considered to be highly uncertain. These emissions are typically estimated based upon a single or a few emission stack tests. The lack of continuous monitoring contributes to a high uncertainty level not only for estimated annual mercury emissions but also the percentage of the various mercury species (i.e. elemental, ionic, particulate) that comprise the types of mercury released by facilities. While several pollutants are often estimated based only on a few emission tests, the uncertainty level for mercury is exacerbated by the fact that mercury content in coal can vary significantly from one region to the next, as well as within different coal seams within the same mine. Therefore, the annual mercury emissions will be based upon the mercury content of the specific coal that was used during the emissions test, which may not be representative of the mercury content in coal that is used throughout the year at the facility. In other cases, emission factors may be used to estimate annual emissions instead of emission test results at the power plant. These emission factors are often selected from a range of values for the specific coal type being used. However, they may not be representative of the mercury content in the coal used by the power plant.[43]

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[43] Senes Consultants, *Evaluation of Technologies for Reducing Mercury Emissions from the Electric Power Generation Sector*, February 2002.

5. Greenhouse Gas Emissions

5.1 Overview

Environment Canada provides annual GHG emission estimates for Canada and for each of the provinces and territories.[44] Alberta accounted for approximately 31% of Canada's total GHG emissions in the year 2000. Emissions in Alberta have been forecast by the Analysis & Modelling Group (AMG) in collaboration with Natural Resources Canada working under the National Climate Change Process. AMG projects GHG emission in Alberta will reach approximately 264 megatonnes CO_2e by 2010. Most of the increases are associated with oil sands developments, electric power generation and transportation.

Table 47: Summary of GHG Emissions in Alberta

(Megatonnes CO_2e)

Source Category	1990	2000	2005	2010	2015	2020	Change 2000 to 2005	Change 2000 to 2010	Change 1990 to 2010	Change 2000 to 2020
Electric power generation	40	51	53	57	57	58	4%	12%	43%	14%
Total industrial	22	30	28	30	35	39	-7%	1%	38%	29%
Residential heating	7	8	7	6	6	6	-19%	-24%	-13%	-30%
Commercial/institutional	5	5	5	5	5	5	0%	0%	0%	0%
Fossil fuel industries	56	78	104	118	123	120	33%	51%	111%	54%
Transportation	23	31	27	28	29	32	-13%	-10%	22%	3%
Agricultural: soils, manure, livestock	17	19	18	19	19	20	-5%	0%	12%	5%
Waste, HFC, Miscellaneous	1	1	1	1	1	1	0%	0%	0%	0%
Total GHG Emissions	171	223	242	264	275	280	9%	19%	55%	26%
Canada Total	607	726	752	810	837	864	4%	12%	33%	19%

Source for 1990, 2000 emissions is Environment Canada.[45] http://www.ec.gc.ca/pdb/ghg/ghg_docs/2000nir_e.pdf.. Source for forecast emissions from 2005 to 2020 emissions, Analysis and Modelling Group/Natural Resources Canada, *Canada's Emissions Outlook: An Update, (CEOU)* Dec. 1999, HALOA Inc. MARKAL. Source for upward adjustments to CEOU (included in above forecast) from AMG/Natural Resources Canada, email correspondence to Cheminfo Services from AMG, Feb 26, 2002.

It should be noted that the estimates of GHG emissions shown in the table above are close but do not exactly match the emissions derived from by MARKAL and presented elsewhere in this Appendix.

The portion of Alberta's total GHG emissions addressed in the scope of the Major Feasibility Study is estimated to be approximately 60% to 70%. Transportation, agricultural, heating of buildings (residential, commercial, institutional), small manufacturing and many other sources are not encompassed by the scope of the study.

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[44] Environment Canada, *Canada's Greenhouse Gas Emissions: 1990 to 2000*, June 2002.

[45] Environment Canada, *Canada's Greenhouse Gas Emissions: 1990 to 2000*, June 2002.

Table 48: Historical Profile of Energy-Based GHG Emissions in Alberta

(Megatonnes CO_2e)

FUEL COMBUSTION	1990	2000	% Change 1990 to 2000
Fossil Fuel Industries	30,900	44,400	44%
Electricity & Heat Generation	40,200	51,000	27%
Mining	2,400	4,160	73%
Manufacturing	9,400	12,400	32%
Pulp and Paper	394	584	48%
Chemicals	3,950	4,820	22%
Construction	236	171	-28%
Transport	21,900	28,300	29%
Pipelines	1,270	2,670	110%
Residential	6,630	8,280	25%
Commercial & Institutional	4,950	4,790	-3%
Other	468	361	-23%
COMBUSTION SUBTOTAL	118,000	156,000	32%
FUGITIVE			
Solid Fuels (i.e. Coal Mining)	240	210	-13%
Oil & Gas	25,000	34,000	36%
Oil Sand and Heavy Oil Upgrading activities	89	880	889%
Natural Gas Distribution	8,100	10,000	23%
FUGITIVE SUBTOTAL	25,000	34,000	36%
ENERGY TOTAL	143,000	190,000	33%

Table 49: Historical Profile of Non-Energy-Based GHG Emissions in Alberta

(Megatonnes CO_2e)

INDUSTRIAL PROCESSES	1990	2000	% Change 1990 to 2000
Non Metallic Mineral Production	869	1,070	23%
Cement	679	924	36%
Lime	190	150	-21%
Adipic & Nitric Acid Production	660	670	2%
Ferrous Metal Production	0	0	
Aluminum & Magnesium Production	0	0	
Other & Undifferentiated Production	7,300	9,800	34%
Fossil Fuel Industries non energy use of fossil fuels	1,500	2,200	47%
Undifferentiated Non Energy Use of Fossil Fuels	5,800	7,500	29%
INDUSTRIAL PROCESSES TOTAL	8,800	11,000	25%
SOLVENT & OTHER PRODUCT USE	38	45	18%
AGRICULTURE			
Enteric Fermentation	5,100	6,500	27%
Manure Management	1,800	2,200	22%
Agricultural Soils**	10,000	10,000	0%
AGRICULTURE TOTAL	17,000	19,000	12%
LAND USE CHANGE & FORESTRY *	100	300	200%
WASTE			
Solid Waste Disposal on Land	870	1,000	15%
Wastewater Handling	140	160	14%
Waste Incineration	0	0	
WASTE TOTAL	1,000	1,200	20%
TOTAL	171,000	223,000	30%

Notes:

Due to rounding, individual values may not add up to totals (zero values may represent estimated quantities too small to display).

Ammonia production emissions are included under undifferentiated production at the provincial level.

Methane and Nitrous Oxide emissions from prescribed fires and anthropogenic fires outside the Wood Production Forest. Fires located in

Emissions associated with the use of HFCs, PFCs, limestone and soda ash are reported in the national total.

** Only one significant figure shown due to high uncertainty.

National Parks are not included in the provincial/territorial total but are reported in the national total.

6. Coverage for Major Point Sources

6.1 Overview

This study focuses on pollutants that are emitted from major industrial point sources and from the electric power generating sector. Over 60% of GHG, SOx, NOx and mercury emissions are encompassed. A much lower portion of VOC emissions, which have large biogenic sources, and PM emissions, which have many area sources (road dust, etc.), are included.

Table 50: Estimated Percentage Emissions from Major Point Sources

(% of Total Emissions in Alberta)

Contaminant	Coverage
PMT	1%
PM10	2%
PM2.5	7%
NOx	80%
SOx	60%
VOC	22%
GHG	60-70%
Mercury	~95%

The table below provides an estimate of the emissions encompassed in the scope of the study. The portion of total Alberta CAC emissions covered in this analysis varies significantly by pollutant due to the nature of the emission sources. For example, natural sources, which represent a large portion of VOC emissions in the province are not covered. Similarly, since the study is focused on major point sources, only, many small facilities/sources are not encompassed and emissions covered by the study will be less than total sector emissions. In fragmented sectors featuring many small sources (such as "Other manufacturing", upstream oil and gas, chemical sectors), the portion of emissions covered is significantly lower than in sectors where the major point sources account for all or the majority of emissions (e.g., electric power generation, oil refining, cement).

Table 51: Major Alberta Point Source Emission Amounts and Percentages of Total Emissions, Based on 2010 Emissions

(kilotonnes)

	PMT	PM10	PM2.5	NOx	SOx	VOC
Total Alberta Emissions	**6878**	**2032**	**327**	**561**	**851**	**2256**
Estimated Emissions Covered by Study*						
Electric power generation	9	7	6	116	97	1
Oil and gas	17	9	6	319	371	494
Cement	1	0	0	2	4	0
Pulp and paper	2	2	2	2	4	0
Petroleum refining	1	1	1	8	4	1
Chemicals	1	1	0	2	19	9
Iron and steel (rounds to zero, less than 0.5)	0	0	0	0	0	0
Other manufacturing	21	11	7	0	8	0
Total	53	31	23	450	508	505
Estimated % of AB emissions	**PMT**	**PM10**	**PM2.5**	**NOx**	**SOx**	**VOC**
Electric power generation	0.1%	0.3%	2.0%	20.6%	11.4%	0.1%
Oil and gas	0.2%	0.5%	2.0%	56.9%	43.7%	21.9%
Cement	0.0%	0.0%	0.0%	0.4%	0.5%	0.0%
Pulp and paper	0.0%	0.1%	0.5%	0.4%	0.4%	0.0%
Petroleum refining	0.0%	0.0%	0.3%	1.4%	0.5%	0.0%
Chemicals	0.0%	0.1%	0.1%	0.4%	2.2%	0.4%
Iron and steel	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other manufacturing	0.3%	0.5%	2.1%	0.0%	0.9%	0.0%
Coverage as % of AB emissions	**1%**	**2%**	**7%**	**80%**	**60%**	**22%**

* may be less than 100% of sector emissions

7. Ambient Air Quality in Alberta

7.1 Summary

Alberta's annual average Ambient Air Quality Guideline (AAQG) concentrations for SOx and NOx are 11 ppbv and 32 ppbv, respectively. Hourly Ambient Air Quality Guideline concentrations for SOx and NOx are 172 ppbv and 212 ppbv, respectively. Alberta does not have standards for total hydrocarbons (THC) or VOCs.[46] However, Alberta does have standards for a number of individual hydrocarbons, such as acetaldehyde, acetic acid, acetone, benzene and others. Alberta's AAQG concentration for ozone is 82 ppbv for a 1-hour average.

Concentration data for numerous ambient air monitoring stations throughout Alberta show that all stations were above 99.98% compliant with Alberta's AAQG for both SOx and NOx (100% for NOx) in terms of the number of hourly exceedances between 1995 and 2000. Annual averages from some monitoring stations in Edmonton and Calgary were close to the guideline value (i.e., within 6 ppb) for NOx. Annual averages of THC concentrations from 20 monitoring stations in Alberta showed little variation from station to station.

Locations with the some of the highest concentrations for NOx and SOx are the major urban areas within Alberta, namely in and around the cities of: Calgary; Edmonton; Red Deer; Fort Saskatchewan; and Fort McMurray. Monitoring data in these areas show concentrations generally below the ambient air quality guidelines. Therefore a constraint on emissions at the current levels would ensure that ambient air quality would remain below guidelines. A reduction in emissions would reduce ambient air concentrations even further below guidelines. If emission trading were instituted, the pattern of ground-level concentrations would change. Trades into areas where concentrations already approach guideline values would need to be monitored to ensure that the resulting air quality does not exceed any of the guidelines.

Linking point source emissions to ambient air quality is outside the scope of this study. The examination of such links requires dispersion models, meteorological information and topographic data for the entire province. Levelton Engineering Inc. provides a more detailed discussion of some of these complexities.[47]

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[46] Few jurisdictions have ambient air quality guidelines for total VOC concentrations.

[47] Environment Canada, *Alberta Demonstration Project For The CASA PM And Ozone Project Team*, September 2002

7.2 Ambient Air Quality Standards

Alberta's Ambient Air Quality Guidelines (AAAQG) are provided in the Table on the next page, along with relevant Canada-Wide Standards (CWS).

Table 52: Summary of Alberta Ambient Air Quality Guidelines and Canada-Wide Standards

	AAQG	AAQG	CWS
Sulphur Dioxide (SO2)	(µg/m^3)	(ppbv)	(ppbv)
1-hour average	450	172	
24-hour average	150	57	
Annual arithmetic mean	30	11	
Nitrogen Dioxide (NO2)			
1-hour average	400	212	
24-hour average	200	106	
Annual arithmetic mean	60	32	
Carbon Monoxide (CO)			
1-hour average	15 mg/m^3	13 ppm	
8-hour average	6 mg/m^3	5 ppm	
Annual Average	-	-	
Ground Level Ozone (O3)			
1-hour average	160	82	
8-hour average			65
Total Suspended Particulates (TSP)			
24-hour average	100		30 ug/m^3 [c] PM$_{2.5}$
Annual geometric mean	60		

[a] The CWS is for PM2.5 rather than TSP

Source: Alberta Environment, *Alberta Ambient Air Quality Guidelines*, February 2000

7.3 Ambient Air Quality Monitoring Results for Year 2000

Ambient air quality is monitored at many stations across Alberta. There are 4 operators of monitoring stations: Industry, Airsheds, Alberta Environment and Environment Canada. Air quality data from Airshed, Alberta Environment and Environment Canada stations are collected in the Clean Air Strategic Alliance (CASA) data warehouse. CASA does not provide data from the industrial monitoring stations. Data from 26 monitoring stations across Alberta was collected for various air pollutants from the CASA data warehouse for this analysis. The following table provides the year 2000 annual average monitoring results for various air pollutants for those stations.

Table 53: Year 2000 AQ Monitoring Results by Station

(Annual Average of Hourly Concentrations)

Monitoring Station	Region	SO2	NO2	PM10	THC	O3
		ppb	ppb	ug/m3	ppm	ppb
Calgary Central	6		28.1	23.15	2.09	14.7
Calgary East	6	2.9	25.8		2.23	16.1
Calgary Northwest	6		16.3		2.12	21.4
Crossfield Carstairs	6	0.9	8.8		1.87	20.9
Alix	8	2.2	4.2		2.01	25.8
Red Deer	8	0.7	13.6	19.62	2.31	19.7
Caroline	9	1.3	4.1		2.26	25.8
Edmonton Central	11		24.9		1.93	15.4
Edmonton East	11	2.4	18.4	21.53	2.50	21.1
Edmonton Northwest	11		21.7	22.30	2.28	16.8
Fort Saskatchewan (9209a - 96 Ave.)	11	1.1	13.5		2.03	20.9
Sherwood Park	11	2.2			2.06	
Tomahawk	11	1.1	4.9	10.82		28.7
Violet Grove	11	0.9	3.7		2.27	33.8
Carrot Creek	14	1.3	6.9			27
Hightower Ridge	15	0.2	0.5	5.36		44.9
Steeper	15	0.1	1.2	8.58		38.8
Buffalo Viewpoint	16	1.3			2.06	
Fort Chipewyan	16	0.2	1			27.5
Fort McKay	16	0.9	5.9		1.91	19.7
Fort McMurray Athabasca Valley	16	0.7	9.4		2.00	17.1
Fort McMurray Patricia McInnes	16	1.1	4.6		1.92	22.9
Lower Camp	16	1.8			2.02	
Mannix	16	2.2			1.95	
Mildred Lake	16	1.9			2.21	
Beaverlodge	19	0.5	3.4			27.3
Annual Avg. AAAQ Guidelines		11	32	60 (TSP)	NA	
National AAQ Guidelines						15.3

Source: CASA Data Warehouse

The annual monitoring data shows that for SOx, the stations measuring the highest levels (Calgary East, Alix, Edmonton East, Sherwood Park and Mannix) are all well below the AAAQ annual average guideline of 11 ppb. However, NOx measurements for stations in Edmonton, Red Deer and Calgary are in some cases as much as 90% of the annual average guidelines, and may be a cause for concern.

Alberta Environment has analysed 1-hour exceedances data for NOx and SOx for all of the monitoring stations in the province, including industrial compliance stations. These results are presented below for 1994 to 2000. This method of analysis found SOx levels to be in exceedance of the guidelines far more often than NOx levels. This change is due to the inclusion of the industrial monitoring stations, which are located downwind of major point sources, generally away from the urban areas.

Table 54: Sulphur Dioxide - Summary of Exceedances from Alberta Continuous Monitoring Stations

Year	# of Monitoring Months	# of Stations	# Above 1-hour Guideline	Peak (ppm)	% Exceedances*	% Compliance
1994	1159	140	103	0.468	0.012	99.988
1995	1127	135	136	0.75	0.017	99.983
1996	1091	131	52	0.6	0.007	99.993
1997	1045	123	32	1.31	0.004	99.996
1998	929	112	18	1.33	0.003	99.997
1999	1040	120	28	0.77	0.004	99.996
2000	987	116	13	0.33	0.002	99.998

* % exceedances = # of hourly exceedances/(# of monitoring months x 730 hours/month (732 for leap years))

Source: Alberta Environment, data provided by Bob Myrick

Table 55: Nitrogen Dioxide - Summary of Exceedances from Alberta Continuous Monitoring Stations

Year	# of Monitoring Months	# of Stations	# Above 1-hour Guideline	Peak (ppm)	% Exceedances*	% Compliance
1994	445	41	1	0.221	0.000	100.000
1995	426	43	0	0.154	0.000	100.000
1996	430	41	1	0.27	0.000	100.000
1997	414	39	0	0.206	0.000	100.000
1998	420	39	0	0.16	0.000	100.000
1999	482	43	0	0.127	0.000	100.000
2000	503	51	0	0.11	0.000	100.000

* % exceedances = # of hourly exceedances/(# of monitoring months x 730 hours/month (732 for leap years))

Source: Alberta Environment, data provided by Bob Myrick

7.4 Ambient Air Quality Modelling Results

Alberta Environment has modelled SO_2 and NOx annual average concentrations for Alberta using mesocale dispersion models which link emissions and meteorological data to ambient air concentrations in the province, allocated in a mesh of 'nodes' across the province. The main purpose of the modelling has been to calculate acid deposition on a regional basis. The following tables provide modelled ambient air quality data for NOx and SOx concentrations in 1995 as modelled by Alberta Environment. The resolution of the modelled results is 1 degree latitude by 1 degree longitude, and were calculated using the 1995 emissions inventory and 1995 meteorological data inputs. The data shows, that SOx and NOx concentrations (upwind and downwind) around Regions 6 and 11 are well within the AAAQ guidelines of 11 ppb and 32 ppb, respectively. The node at (51°,114°) occurs within Calgary proper.

Table 56: AAQ Modelling Results for Regions 6 and 11: Calgary and Edmonton Areas

(1995 Annual Average Concentrations*)

	Nodes		NO2		SO2	
	Lat.	Long.	(µg/m3)	ppb	(µg/m3)	ppb
Region 6						
~115 km South of Central Calgary	50	114	3.18	1.69	2.74	1.05
Calgary Central	51	114	4.82	2.56	4.39	1.68
~115 km North of Central Calgary	52	114	4.76	2.53	3.80	1.45
Region 11						
~115 km Southwest of Central Edmonton	53	115	5.18	2.75	5.13	1.96
~70 km Southwest of Central Edmonton	53	114	6.96	3.70	4.89	1.87
~70 km Southeast of Central Edmonton	53	113	5.05	2.69	3.27	1.25
~70 km Northeast of Central Edmonton	54	113	2.33	1.24	1.53	0.58
AAAQG				32		11

*Modelled Using 1995 Emissions and Meteorological Data
Source: Alberta Environment, data provided by Lawrence Cheng

Results from monitoring stations (from 1995 in Calgary, Edmonton and Fort Saskatchewan) are provided below. This data also shows that the regions are within the AAAQG.

Table 57: AAQ Modelling Results for Regions 12 and 16

(1995 Annual Average Concentrations[*])

Lat.	Long.	NO2	SO2	NO2	SO2		Lat.	Long.	NO2	SO2	NO2	SO2
		(µg/m3)	(µg/m3)	ppb	ppb				(µg/m3)	(µg/m3)	ppb	ppb
54	112	1.82	1.34	0.97	0.51		58	112	0.25	0.81	0.13	0.31
54	111	1.58	1.50	0.84	0.57		58	111	0.25	0.87	0.13	0.33
54	110	1.33	1.41	0.71	0.54		58	110	0.25	0.70	0.13	0.27
55	112	1.13	1.46	0.60	0.56		59	114	0.13	0.22	0.07	0.09
55	111	1.24	2.01	0.66	0.77		59	113	0.11	0.26	0.06	0.10
55	110	1.05	2.05	0.56	0.78		59	112	0.11	0.34	0.06	0.13
56	112	1.24	4.89	0.66	1.87		59	111	0.10	0.33	0.06	0.13
56	111	1.18	4.89	0.63	1.87		59	110	0.10	0.31	0.05	0.12
56	110	0.80	2.37	0.43	0.90		60	115	0.07	0.12	0.04	0.05
57	112	0.71	3.70	0.38	1.41		60	114	0.06	0.11	0.03	0.04
57	111	0.60	2.74	0.32	1.05		60	113	0.06	0.16	0.03	0.06
57	110	0.58	1.48	0.31	0.57		60	112	0.06	0.17	0.03	0.07
58	114	0.27	0.50	0.14	0.19		60	111	0.05	0.14	0.03	0.05
58	113	0.24	0.64	0.13	0.25		60	110	0.05	0.12	0.02	0.05

[*] Modelled Using 1995 Emissions and Meteorological Data

Source: Alberta Environment, data provided by Lawrence Cheng

7.5 Influence of Emissions From Surrounding Regions

In this section, Alberta's annual CAC emissions are compared to those of the surrounding American states and Canadian provinces that can contribute to the air quality in Alberta. States covered in this analysis include Alaska (AK), Washington (WA), Oregon (OR), Idaho (ID) and Montana (MT). Provinces covered are British Columbia (BC) and Saskatchewan (SK). CAC emissions from industrial, electric power generation (EPG) and transportation are used for the basis of comparison. Industrial and EPG sources represent the great majority of SOx emissions. It is also these emission source categories for which emissions data at the state level are readily available. Transportation NOx and other emissions could not be found for each American state, although transportation NOx was for the total United States. State-specific transportation emissions by pollutant were therefore estimated for the purpose of this comparison using a simplifying assumption.[48] The most recent available - 1999 - American state CAC emissions data are applied.

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[48] The assumption is that the ratio transportation emissions to total industrial plus EPG emissions for the United States, as a whole is in the same ratio in the surrounding states. This is a simplifying assumption that only provides an order-of-magnitude estimate (suitable for this comparison analysis) of the Transportation emissions in the surrounding states. Actual transportation emissions were not readily available by state.

Comparable AB, BC and SK emissions data for 1999 have been estimated (based on interpolation using 1995 actual data and forecast 2000 data).[49]

Table 58: Comparison of Industrial, Electric Power Generation and Transportation CAC Emissions Between Alberta and Surrounding Regions, 1999

(Estimated 1999 Emissions for Alberta, BC and SK - kilotonnes)

Region	PM10	PM2.5	NOx	SOx	VOC	CO
Alberta	54	42	721	515	638	1162
Surrounding States (AK, WA, OR, ID, MT)	73	48	354	232	165	2210
BC	104	81	320	174	180	1301
SK	57	22	210	138	175	471
Ratio of Alberta Emissions to Surrounding Regions' Emissions						
Surrounding States	75%	87%	203%	222%	386%	53%
BC	52%	52%	226%	295%	355%	89%
States plus BC	31%	33%	107%	127%	185%	33%
SK	95%	189%	344%	374%	364%	247%
Ratio of Surrounding Regions' Emissions to Alberta Emissions						
Surrounding States	134%	115%	49%	45%	26%	190%
BC	192%	192%	44%	34%	28%	112%
States plus BC	325%	307%	93%	79%	54%	302%
SK	105%	53%	29%	27%	27%	40%

Source: US EPA, Environment Canada for 1999 emissions based on forecast of 1995 emissions.

The analysis shows that Alberta's major NOx and SOx emission sources (i.e., industrial, EPG and transportation) are greater than any other's single state or province emissions from comparable sources. Alberta emissions of SOx and NOx are approximately double the emissions from surrounding American states. However, Alberta's emissions are approximately equal to the total of the emissions from the surrounding states and BC. Alberta's VOC emissions from industrial and transportation sources (there are negligible amounts of VOC from the electric power generating sector) greatly exceed the VOC emissions from the surrounding states and BC. Alberta's emissions are least 3 times greater than the sum of the surrounding states, as well as approximately 3 times greater than BC's and SK's VOC emissions.

One major factor that contributes to Alberta's larger emissions is the Upstream Oil & Gas sector, which includes the existing oils sands mining and bitumen upgraders. BC, SK as well as the surrounding states also have conventional oil and gas sector production activities. However, the size of the sectors in surrounding regions is much smaller than the sector in Alberta. Oils sands and bitumen upgraders are not present in BC or surrounding states. The other major factor that contributes to Alberta's SOx and NOx emissions being larger than those in the surrounding regions is the use greater use of coal for electricity generation. BC has no coal-based electricity generation. It relies on hydro power and a minor amount of electricity generated with natural gas.

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[49] Actual 1999 CAC emissions inventories for the Canadian provinces do not exist in readily available, consolidated form.

There are some exceptions to the general rule that Alberta's emissions are greater than emissions in surrounding regions. In the case of PM, Saskatchewan's emissions PM10 emissions are estimated to have been greater than Alberta's in 1999. This was caused by the lack of PM controls on one of Saskatchewan's major EPG sector facilities - i.e., Boundary Dam. Without electrostatic precipitators or baghouses, as exist on Alberta's EPG facilities, the uncontrolled PM emissions from that SK facility were quite substantial. Currently, the Boundary Dam facility is in the process of installing PM control systems to address over 95% of its PM emissions.

Given that, Alberta's emissions are greater than those of the surrounding regions, it can be generally concluded that the emission sources within the province, will have the greatest effect on local ambient air quality. The exact quantitative effect of transboundary pollutant transfers from other regions entering Alberta is unknown and would require complex air quality modelling to determine. However, it can be concluded that transboundary emissions will likely have a minor effect on Alberta air quality that for most, if not all, regions in Alberta will be a very small fraction of the effect of local emission sources within the province. The reason for this is, in part, that only a fraction of the emissions from other regions enter Alberta.

Alberta Environment has studied the transboundary transport of SOx and NOx in Alberta (Cheng, Angle).[50] Based on ambient air quality modelling of emissions in Alberta and surrounding regions, it was concluded that approximately 10% of sulphur in the province was transported from British Columbia. Similarly, British Columbia represented 18% of the total sources of NOx entering Alberta air space. Given that the prevailing winds through Alberta are from the west, the study concluded that the majority of Alberta emissions are transported into Saskatchewan, while some of the rest travel to Northwest Territories, Manitoba and the United States. The study did not consider transboundary influence of U.S. emissions into Alberta.

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[50] Cheng, L., Angle, R.P., (1996) *Model-Calculated Interannual Variability of Concentration, Deposition and Transboundary Transport of Anthropogenic Sulphur and Nitrogen in Alberta,*

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Draft letter

Ron Hicks

Dear EPAC members:

We had originally planned to have the next Environmental Protection Advisory Committee (EPAC) meeting in Edmonton on May 27. Due to other commitments that the Minister has in Calgary, we will move the location to the McDougall Centre in Calgary. Please note that the meeting will be from 10:00 a.m. to 3:00 p.m.

Attached is the draft agenda for the meeting. Additional material will be provided before the meeting.

Please contact Keith Leggat (780 427 2234; keith.leggat@gov.ab.ca) if you have any questions or comments about the committee.

Ron Hicks

Cc Honourable Lorne Taylor